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BEFORE THE

ARIZONA CORPORATION COMMISSION

E-00000A-02-0051
E-01345A-01-0822
E-00000A-01-0630
E-01933A-02-0069
E-01933A-98-0471

Supplemental Affidavit of

Charles J. Cicchetti, Ph.D.

Docket No. E-00000A-02-0051, et al.

On Behalf of

Arizona Public Service Company

June 26, 2002

Arizona Corporation Commission
DOCKETED

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1. My name is Charles J. Cicchetti. I previously testified before the Arizona Corporation Commission in the Generic Electricity Competition proceeding. When I was cross-examined, I was asked to review my files for two types of information. I have now done so.
2. The first matter relates to my checking the California data files to determine whether Panda or TECO traded together or separately in either the California Power Exchange (CPX) or California Independent System Operator (CAISO) markets during the California Refund Period of October 2, 2001 through June 20, 2001. In reviewing the data in the FERC proceeding, I can confirm that neither Panda nor TECO traded as a Scheduling Coordinator (this is the level of aggregation in the FERC related data) in these California energy markets.
3. I have confirmed with respect to the second matter I was requested to check that Panda proposed two merchant operating plants in Florida and that I became familiar with these applications, as well as a similar filing by PG&E with respect to the Okeechobee Generating Plant. The two separate Panda filings were in Lake County (the Leesburg Power Partners, L.P.) and St. Lucie County (Panda Midway Power Partners, L.P.). All three generating units employed the same economic consultant in their respective Need Petitions. This consultant was Dr. Dale Nesbitt (Altos Management Partners).
4. Dr. Nesbitt's analyses in all three merchant generating cases were predicated on a wholesale arrangement in which merchant generators

would be paid on the basis of maximum supply stack marginal production costs. Accordingly, my detailed testimony in the first of these applications (PG&E's Okeechobee in Florida Power's territory) demonstrates that Florida's retail electricity consumers would pay much more over a 30-40 year life and the merchant owner would expect to earn much more profit as compared to either a traditional cost of service treatment or a long-term bilateral amortization using traditional utility type financing. I have attached the testimony and exhibits I filed in that proceeding as Exhibit A to this affidavit.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge. Executed this 26th day of June 2002, at Pasadena, California.

Charles J. Clcchetti

EXHIBIT A

FILE

BEFORE THE PUBLIC SERVICE COMMISSION

INTERVENOR TESTIMONY OF

CHARLES J. CICCHETTI

DOCKET NO. 991462

On behalf of

FLORIDA POWER CORPORATION

JAMES A. McGEE
Senior Counsel
FLORIDA POWER CORPORATION
P.O. Box 14042
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

GARY L. SASSO
Florida Bar No. 622575
JILL H. BOWMAN
Florida Bar No. 057304
Carlton, Fields, Ward,
Emmanuel, Smith & Cutler,
P.A.
Post Office Box 2861
St. Petersburg, FL 33731
Telephone: (727) 821-7000
Telecopier: (727) 822-3768

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR DETERMINATION OF NEED FOR THE

OKEECHOBEE GENERATING PROJECT, FPSC DOCKET NO. 991462-EU

DIRECT TESTIMONY OF CHARLES J. CICCHETTI, PH.D.

SECTION I: INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles J. Cicchetti. My address is Pacific Economics Group, 201 South Lake Street, Suite 400, Pasadena, California 91101.

Q. WHAT IS YOUR POSITION WITH PACIFIC ECONOMICS GROUP?

A. I am a Co-Founding Member of Pacific Economics Group.

Q. WHAT ARE YOUR DUTIES AS A MEMBER OF PACIFIC ECONOMICS GROUP?

A. I actively consult with clients on price, costs, environmental, natural gas and electricity market issues and antitrust policies, particularly as those policies relate to regulated industries.

Q. DO YOU HOLD ANY OTHER POSITIONS?

A. I am the Jeffrey J. Miller Chair in Government, Business, and the Economy at the University of Southern California.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I attended the United States Air Force Academy and I received a B.A. degree in Economics from Colorado College in 1965 and a Ph.D. degree in Economics from Rutgers University in 1969. From 1969 to 1972, I engaged in post-doctoral research at Resources for the Future.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I served as chief economist for the Environmental Defense Fund from 1972 to 1975, and was a faculty member at the University of Wisconsin from 1972 to 1985, ultimately earning the title of Professor of Economics and Environmental Studies. From 1975 through 1976, I served as the Director of the Wisconsin Energy Office and as Special Energy Counselor for the Governor. In 1977, I was appointed by the Governor as Chairman of the Public Service Commission of Wisconsin and held that position until 1979 and served as a Commissioner until 1980. In 1980, I co-founded the Madison Consulting Group, which was sold to Marsh & McLennan Companies in 1984, and merged into National Economic Research Associates, and I became Senior Vice President and held that position until 1987. From 1987 until 1990, I served as Deputy Director of the Energy and Environmental Policy Center at the John F. Kennedy School of Government at Harvard University and from 1988 to 1992, I was a Managing Director and ultimately Co-Chairman of the economic and management consulting firm, Putnam, Hayes & Bartlett, Inc. In 1992, I served as National Director and formed Arthur Andersen Economic Consulting, a division of Arthur Andersen, LLP. In 1996, I left Arthur Andersen to co-found Pacific Economics Group. In 1998, I accepted the Jeffrey J. Miller Chair at the University of Southern California.

Q. HAVE YOU PUBLISHED ANY PAPERS OR ARTICLES?

A. Yes. I have published a number of articles on energy and environmental issues, public utility regulation, competition and antitrust. A complete listing of my publications is included in Exhibit CJC-1.

Q. HAVE YOU EVER GIVEN EXPERT TESTIMONY IN A COURT OR ADMINISTRATIVE PROCEEDING?

A. Yes. A list of the proceedings in which I have provided expert testimony since 1980 is also included in Exhibit CJC –1.

Q. WHO RETAINED YOU FOR THIS TESTIMONY?

A. I have been retained by Florida Power Corporation (FPC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to consider and address the prefiled testimony submitted by Dr. Dale Nesbitt, who appears for the Petitioner, in support of permitting the Okeechobee Generating Company (OGC) to enter the Florida market under current rules, regulations and conditions. In so doing, I analyze the relevant economic and regulatory principles that should be applied by the Florida Public Service Commission (the "FPSC" or "Commission") in making its decision.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes.

- Exhibit CJC-1 is my resume.
- Exhibit CJC-2 consists of seven pages. This exhibit shows the way in which a merchant plant would collect its capital costs and contrasts that

with the way in which an incumbent would collect those same capital costs.

- Exhibit CJC-3 consists of five pages. The first page shows graphically the profits that the OGC plant would expect to receive. Pages two and three discuss the assumptions that I used in this Exhibit and presents the steps used in this analysis. Pages four and five are reproductions of Dr. Nesbitt's Exhibits DMN-5 and DMN-6, respectively.
- Exhibit CJC-4 is a copy of the FRCC's Y2K plan.
- Exhibit CJC-5 is a copy of Reliant Energy's initial refusal to operate its plants in response to the FRCC's request that Reliant do so to comply with the FRCC's Y2K plan.
- Exhibit CJC-6 shows the sources of electricity in the State of Florida.
- Exhibit CJC-7 details the purchase power expenses for the three investor owned utilities (IOUs) in Florida.
- Exhibit CJC-8 details the estimated energy costs in Florida.

Q. WHAT ARE THE PRINCIPAL ECONOMIC AND REGULATORY CONCEPTS THAT YOU CONSIDER IN YOUR TESTIMONY?

A. I begin by addressing some very fundamental concepts. These are:

- Perfect competition should not be compared either with: imperfect regulation, biased descriptions of regulation, or the current form of regulation in Florida.

- Competition should not be micromanaged if economic efficiency is to be achieved.
- TANSTAAFL: There Ain't No Such Thing as a Free Lunch. Merchant plants are neither "manna from heaven" nor do they represent the unlikely outcome of pure benefits without costs.
- Deregulation works best in the short-run for consumers when supply exceeds demand, not *vice versa*.
- Rate base, or cost-of-service regulation, is less costly if Florida is relatively certain about what is needed and how it should be supplied.
- Infra-marginal generating stations "priced-to-market" would generally expect to achieve supra-marginal or above-normal returns as they "cream skim the system."
- The economic value of a generation station needs to be forward-looking, not backward or contemporaneous looking.
- Restructuring, customer choice, and competition comprise a political process of "Gives" and "Gets" in which the objectives are clear: lower prices, free entry, new products, customer protection through choice and regulatory policing, and specific mandates and requirements. Merchant plant proposals are simply not on the same page.

If regulators in Florida wanted to place cost-of-service performance on a par with price-to-market merchant plants they could consider expanding performance incentives for rate-base financed generators.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. A. In Section II, by way of background, I begin by addressing each of the economic and regulatory principles I mentioned above, and explain how they have been neglected or misapplied by Dr. Nesbitt. In Section III, I demonstrate that Dr. Nesbitt's claims concerning the savings that the OGC plant would produce for consumers are false and misleading. In Section IV, I address additional arguments that Dr. Nesbitt has made in support of OGC's Petition and explain why those arguments are, at best, misleading and overstated, and, at worst, untrue and purposely obfuscating. In Section V, I summarize my conclusions.

Q. HAVE YOU REVIEWED DR. NESBITT'S PREFILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS YOUR OPINION OF DR. NESBITT'S TESTIMONY?

I admire his enthusiasm and language use. However, his testimony is marred by a lack of both economic and common sense. I find that Dr. Nesbitt's numerical results are so false that he should have discovered or surmised that something was amiss.

I find that Dr. Nesbitt analyzes OGC relative to a world that does not exist in Florida. He uses issues from this world (e.g., alleging potential FPL and FPC market power) that do not pertain in Florida at this time. Worse, he claims a pricing outcome and estimates benefits for a setting with market rules that OGC does not propose to follow.

He overstates OGC's advantages, erroneously claiming that others could not replicate them. He fails to admit OGC's differences, which would shed unfavorable light on OGC's petition. Dr. Nesbitt's testimony is utterly transparent and devoid of any substantive value.

Q. AS A GENERAL PROPOSITION, DOES DR. NESBITT'S TESTIMONY PROVIDE SUPPORT FOR THE COMMISSION GRANTING OGC'S PETITION?

A. No. Dr. Nesbitt grossly overstates any unique case for OGC. (1) Real alternatives are given short shrift and otherwise distorted. (2) The Case for merchant plants over similar plants financed through cost-of-service regulation has not been made. (3) OGC's value is inflated due to the fact that it is compared to Florida's past, not its future, regardless of whether the future is regulated, competitive, or some combination.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. There are three key points that I need to make. First, contrary to Dr. Nesbitt's assertions in this case, the proposed merchant plant would not address reliability issues in Florida. Simply put, a merchant plant that is uncommitted cannot be counted upon for this reliability requirement. The merchant plant is free to sell anywhere and chase high spot prices whenever it chooses. Worse, it uses up scarce resources (transmission, air, water and land) that may, in the future, prevent an incumbent IOU from building a plant that would actually address reliability issues. Unless regulators impose some form of must-run, must-bid, and capped price restrictions on the merchant plant, they simply cannot rely on that plant for reliability purposes at reasonable prices.

Second, the proposed merchant plant would not meet an economic need for additional capacity. Here, Dr. Nesbitt assumes that there is no difference between price and cost. Dr. Nesbitt's assumption is simply not true in a hybrid regulated cost-of-service world where a merchant plant is permitted to price to market. Dr. Nesbitt compounds his error by assuming something that does not exist in Florida, a perfectly competitive electricity market that will discipline merchants. Contrary to his assumption, Florida is a least cost of service or regulated environment that does not distinguish between least price and least cost. Allowing a merchant plant to enter and "compete" in this environment introduces imperfect competition, which will benefit only the merchant to the detriment of the incumbent utilities and their customers.

Third, contrary to what Dr. Nesbitt claims, the proposed merchant plant would not be cost effective for consumers. Compared to the same plant built by an incumbent utility under cost-of-service regulation, the merchant plant will very likely cost consumers significantly more over its life. The merchant plant would have a higher cost of capital and shorter pay back period, which would translate into higher prices for consumers when compared to utility owned generation. Further, over its expected operating life, the merchant plant would collect more revenue from retail ratepayers than the same plant built by an incumbent utility under cost-of-service regulation. This would be anti-consumer and hurt the Florida economy.

SECTION II: BASIC FUNDAMENTAL PRINCIPLES OF REGULATION AND ECONOMICS

Q. LET'S BEGIN WITH YOUR PERSONAL VIEWS ON REGULATION AND COMPETITION. AS A FORMER REGULATOR AND CARD-CARRYING ECONOMIST, ARE YOU PRO-REGULATION OR PRO-MARKET?

A. That is a fair question. I am more pro-market than anything else. However, I have never been accused of having simple views on important matters of public policy.

The world is complex and it is often easy to trash the past or *status quo* when one is on a mission to sell a new approach. Yet, this is precisely what Dr. Nesbitt has done in this case. This is a mistake for two reasons. First, misrepresenting how we got here means that we risk throwing out the good with any bad. Second, it is dangerous to over-promise or exaggerate and, in the process, to establish false, unachievable expectations. Such approaches most likely mean that reforms will fail to live up to their advanced billing.

In this particular context, the promises of achieving perfect competition by granting a license to a merchant plant are incorrectly and unfairly matched up against cost-of-service regulation. This deceptive comparison takes three forms.

1. It is ridiculously averred that incumbent IOUs bear no risk and can rely on regulators to give them a full return "on" and "of" their investments.
2. It is falsely observed that IOUs would, and do, pad their rate base with unnecessary and overly expensive investments, and regulators either look the other way or are inept.
3. It is incorrectly claimed that fringe market competitors can, and will, discipline centrally-dispatched short-term power markets and provide a useful benchmark or yardstick for new incumbent generation investments.

Q. HOW CAN AND DO INCUMBENT IOUs EXPERIENCE RISK UNDER COST-OF-SERVICE REGULATION?

A. Regulators do not necessarily allow all costs incurred by IOUs to be placed in rate base. Regulators sometimes use prudence reviews, hearings on need, and used and useful concepts to disallow costs that they deem excessive. For more than two decades, there are no, and have been no, regulatory guarantees that IOUs and their investors can take to the bank. In addition, there are business, operational, and financial risks that IOUs experience. Also, regulation is mostly asymmetric, with regulators strongly tilting any benefits towards retail consumers, while attempting to avoid passing through all costs. Thus, to imply that IOUs face no risk is to misrepresent cost-of-service regulation and to ignore business, financial, regulatory, economic, and operating risks.

Q. DO REGULATED UTILITIES "PAD" THEIR RATE BASE WITH OVERLY EXPENSIVE CHOICES?

A. No. First, the Averch-Johnson Effect (A-J Effect), which postulates potential rate base padding, is dependent on utility companies expecting to earn rates of return under regulation that exceed their weighted average cost of capital. Just the opposite behavior (*i.e.*, under-investing in costly rate base additions) is hypothesized under the A-J Effect if utilities companies have costs of capital (WACC) that exceed either their authorized regulated or actual rate of return. Under current and past (at least nearly three decades) financial conditions, the necessary A-J Effect conditions that would potentially cause some excess utility investment are simply not present, realistic or consistent.

Second, and more important, regulators across the nation have generally adopted and used integrated resource planning and similar regulatory approaches to insure that unnecessary utility investments are not made, while requiring that necessary investments be made to insure reliability and reasonable costs. All this has taken place with a complementary form of cost-of-service regulation that pushes down to shareholders any costs that regulators find to be excessive or unnecessary. If there have been guarantees, they take the form of a pro-consumer bias.

In short, regulation, certainly for the past decade and a half, has essentially guaranteed that there would be no rate base padding. The opposite tendency (*i.e.*, under-investment) might have been present. However, under-investment in electricity has generally not been a significant problem.

Q. PLEASE EXPLAIN HOW REGULATORS PREVENT UTILITIES FROM OVERBUILDING.

A. Regulators generally use least cost planning to prevent unnecessary investments and to cause necessary investments to be made. Regulators also have sufficient rate making control to ensure that utilities do not overbuild. Regulators can disallow certain costs associated with a plant and prevent their inclusion in rate base. Disallowances at past prudence hearings involving nuclear plants ran into the billions of dollars. Utilities well remember these disallowance and are not likely to overbuild with the omnipresent prudence review threat. Further, regulators can control utilities through the allowed Return on Equity (ROE). Regulators can remove a utility's incentive to overbuild by controlling earnings through simply reducing the allowed ROE relative to the cost of capital. As long as regulators provide just and reasonable returns, utilities will build the correct amount. And even when returns are not high enough, utilities will generally be required to build to satisfy their duty to serve. I find no evidence of overbuilding in the last ten years in the United States.

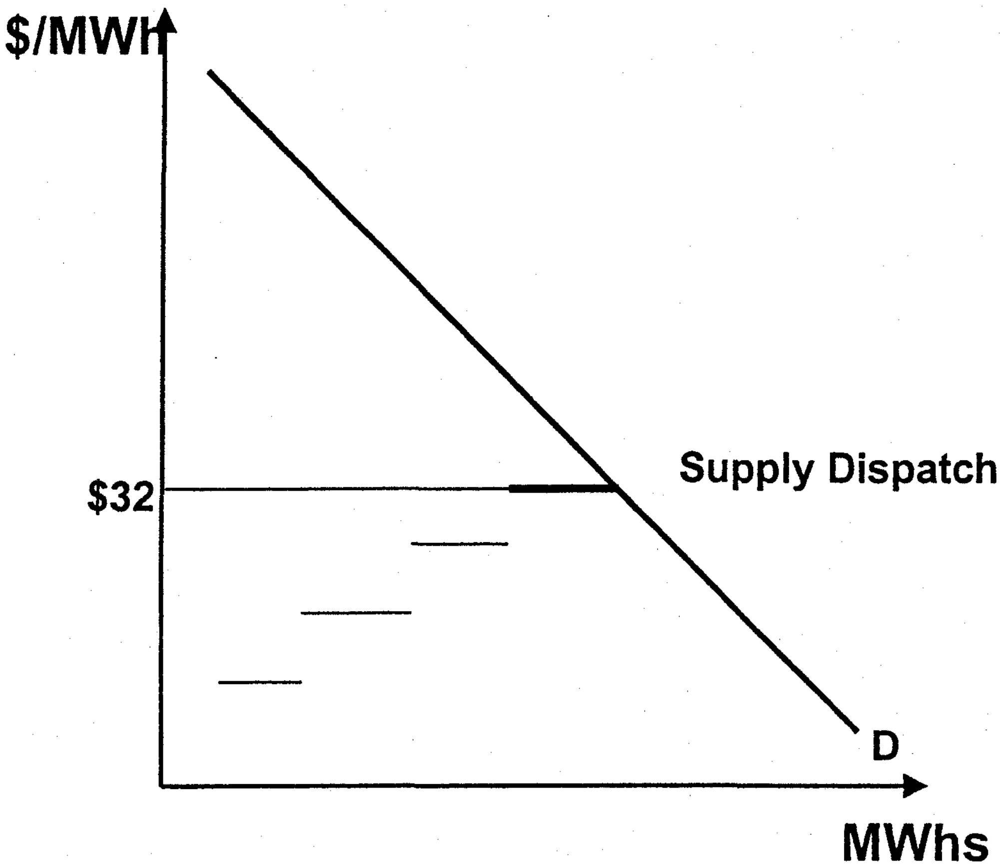
Q. DO YOU DISAGREE WITH DR. NESBITT'S ASSERTION THAT MERCHANT PLANTS WOULD YIELD POSITIVE COMPETITIVE FRINGE MARKET YARDSTICK OR BENCHMARK BENEFITS?

A. Yes, I disagree with this position. In Florida, merchant plants would be entering a pre-existing utility market that already operates in an economically efficient manner under joint generation dispatch conditions. Long-term planning also insures that efficient investments and alternatives are identified and pursued. The "priced-to-market" terms OGC proposes will <u>not</u> serve any yardstick or benchmark function because these units are not "paid" their marginal running costs. Instead, they are paid the market price.

Consider Figure CJC-1A. This shows a supply stack with a $32 clearing price that Dr. Nesbitt and the applicant apparently believed would be the approximate average annual competitive price of electricity in the Florida Peninsula before the merchant plant enters the market.[1] For the discussion that immediately follows, I use Dr. Nesbitt's $32/MWh clearing price. However, I will explain later in my testimony why I disagree with Dr. Nesbitt's $32/MWh clearing price.

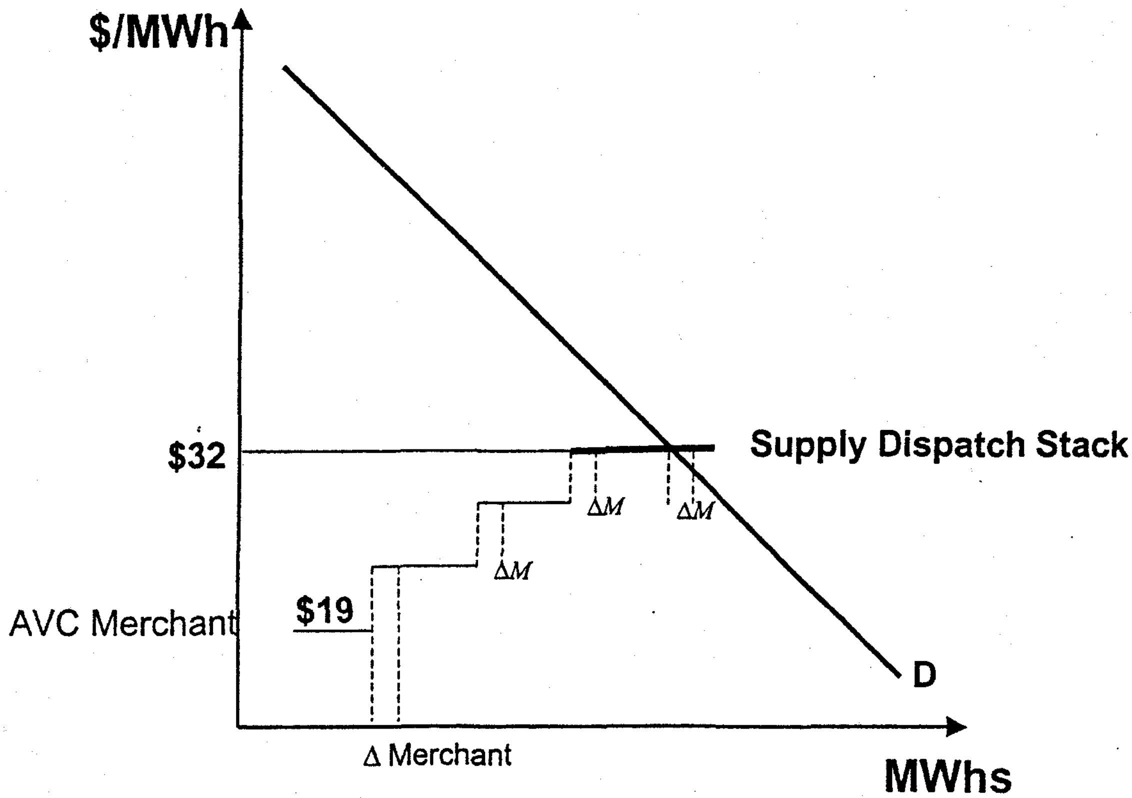
[1] See page 103 of Dr. Nesbitt's testimony in which he states that his model estimates a price of $31.68/MWh, which for discussion purposes I have rounded to $32/MWh.

Figure CJC-1A



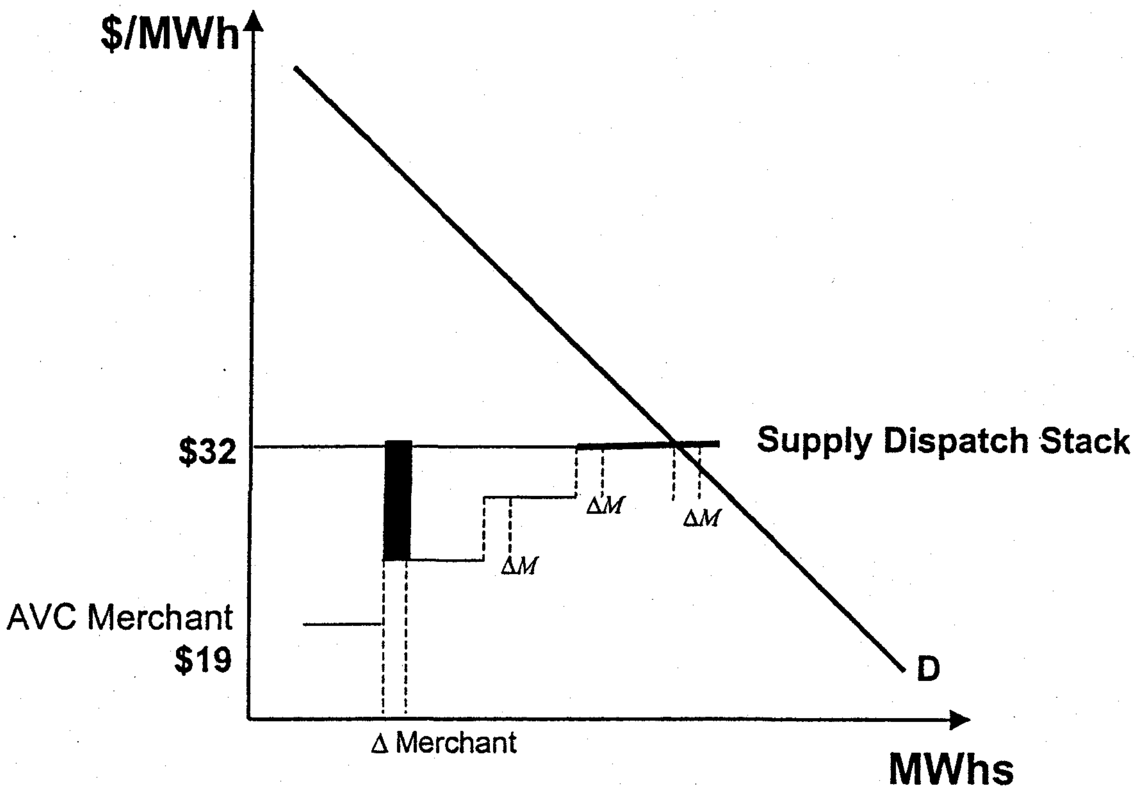
Now consider Figure CJC-1B, which shows the infra-marginal merchant plant being added to the same supply stack, continuing to use applicant's approximate assumption of a $32 MWh price to market sale.

Figure CJC-1B



In CJC-1B, even after the infra-marginal merchant plant enters, the supply dispatch stack (SDS) would still tend to set the market-clearing price at $32 per MWh. This result will hold so long as there are more plants at the $32 per MWh price than are displaced by the merchant plant's output (ΔMerchant.) In CJC-1B, I show the merchant plant coming into the competitive dispatch sequence infra-marginally. This means that it shifts the supply stack to the right by ΔM. However, because the merchant plant is infra-marginal, the market-clearing price remains unchanged at $32 per MWh. The cost, but not the price, of supplying electricity is reduced by the difference in the $32 average variable cost (AVC) that is backed out and the merchant plant's AVC times the merchant plant's output. Had this plant been brought on line by an incumbent IOU under cost-of-service regulation, this cost savings would be used by the IOU to reduce prices. (Any rate base cost recovery of fixed costs also needs to be considered. This is addressed below.) However, under a priced-to-market regime for the merchant plant, regulated prices for energy will remain unchanged. Under cost-of-service regulation, this cost saving reduces prices. With a merchant plant priced-to-market, regulated energy prices stay the same if the merchant plant is infra-marginal. Further, because the market price does not change, the cost savings inure instead as increased profits to the owners of the merchant plant. This result yields no yardstick benefits. Instead, under infra-marginal conditions, it could very likely push merchant plant profit to exceptional levels causing other merchants to attempt to imitate OGC, but not likely seeking competition that would reduce merchant plants' income and effective prices. Consider Figure CJC-1C to understand OGC's profit motive.

Figure CJC-1C



The shaded area above the merchant plant's AVC is the difference between the merchant plant's average variable costs (approximately $19 per MWh) and the assumed market-clearing price ($32 per MWh). This represents the merchant plant's operating profit of $13 per MWh. With restricted entry and central dispatch, this would be a very rewarding outcome for merchant plant owners who would use revenues from the project to recover investment costs and earn income. Regardless, there would be no corresponding yardstick benefits.

Introducing a merchant plant that prices-to-market would also most likely, as I discuss below, mean that consumers pay more for electricity than if IOUs had built the same plant under cost-of-service, or rate base, regulation. Accordingly, I find no yardstick benefits under such an outcome. I find only anti-consumer, ineffective regulation.

Q. HOW DOES REGULATION ACHIEVE ECONOMICALLY EFFICIENT DISPATCH?

A. Competitive markets bring together and match multiple suppliers (generators) against consumers in short-term (hourly) markets. Split saving, centrally dispatched generation in a regulated utility power pool yield the same economically-efficient dispatch result. This is true even in regulated markets with as few as two generation owners that jointly dispatch their generation.

Merchant plants are simply not necessary to achieve operational economic efficiency in generation dispatch. If merchant plants are priced-to-market and do not, and are not expected to, change the market clearing price, their presence is an economic non-event. Nevertheless, merchant plant owners experience significant mark-ups over their average variable costs (AVC). Consumer prices, however, are not reduced due to the merchant plant's entry. Moreover, the opportunity to reduce consumer prices under cost-of-service entry would be reduced. Thus, consumers would most likely pay more, not less, than they would have without merchant plant entry and with similar generation built by an incumbent utility. I expand on this and describe other reasons for this anti-consumer result below.

Q. DR. NESBITT ASSERTS THAT UTILITIES WOULD BUY FROM MERCHANT PLANTS ONLY IF IT WAS THE MOST COST EFFECTIVE PLANT. DO YOU AGREE?

A. I have trouble with Dr. Nesbitt's "cost effective" logic. Even if one were to assume that a merchant plant was the most cost effective plant, it would be cost effective only in the sense that it had the lowest AVC (i.e., running cost) in the market. Under cost-of-service regulation, least price and least cost are the same. This is not necessarily the case with the merchant plant, because even if the merchant plant was the lowest cost plant, it would still require the IOU, and retail consumers indirectly, to pay a price equal to the most expensive alternative in use. In such a situation, regulators should prefer that the utility build the plant itself or enter into long-term firm contracts. In these circumstances, approving the merchant plant would simply not be best for Florida's ratepayers.

Q. EARLIER IN YOUR TESTIMONY, YOU MENTIONED THAT COMPETITION SHOULD NOT BE MICROMANAGED IF ECONOMIC EFFICIENCY IS TO BE ACHIEVED. WHAT DO YOU MEAN BY MICROMANAGING COMPETITION?

A. Several industries and many nations have been restructuring their comprehensively-regulated natural monopolies (e.g. utilities and telephone companies). These changes take several forms: (1) unbundling traditional, allinclusive tariffs that recover commodity, delivery, and customer service costs; (2) separating functions and business units that previously were vertically interconnected into competitive pieces and regulated natural monopoly pieces; (3) encouraging new competitive entry, divestiture, and incumbent restrictions for the purpose of kick-starting competition in those sectors that are deemed not to be natural monopolies; (4) providing for retail customer choice and encouraging the use of new products and services to provide consumer benefits; and, (5) designing and creating new regulatory functions and institutions to restrict any vertical or horizontal market power and to promote competitive market outcomes.

The specific details, processes and policies differ from industry to industry, state to state, and nation to nation. Nevertheless, there is great commonality, some important lessons learned, and some problems to be avoided. The most significant lessons learned, in my experience, have to do with transition rules and regulatory handicaps or restrictions imposed on incumbents.

I have found, in my experience and in the relevant literature, numerous examples of excessive political and regulatory efforts that attempt to micromanage these changes. There are two obvious dangers to avoid. First, economic efficiency will not flow from competition when markets are politically controlled and non-market forces and self-serving entities attempt to cause directed outcomes. Second, if a state or nation is considering changes, it should not compare its past and/or present regulatory circumstances to perfect competitive markets because transition rules that regulate the market and/or market power will prevent the perfectly competitive market from being formed and yielding economically-efficient outcomes.

Third, and most important, regulators should not excessively reward the "first newcomers to enter the restructuring process." This type of regulatory/political request is very often overplayed and exaggerated. I believe regulators and incumbents make the changes possible. Therefore, regulators should claim credit, incumbents should not be victimized, and newcomers should not be given carte blanche to cream-skim and keep huge profits for themselves.

The point I want to emphasize is that much of this is essentially a zero-sum game. The costs and benefits will be the same regardless of who builds an identical new infra-marginal plant. Nevertheless, an important difference is that under cost-of-service regulation, consumers will realize this lower cost benefit. Conversely, under the cost-of-service regulation that exists in Florida today, the merchant plant owner would keep the benefit of the lower costs. Under the current regulatory regime in Florida, consumers, as I explain below, are undeniably better off if an incumbent IOU constructs the plant.

The key conceptual policy point is that imperfect competition is not always superior to cost-of-service regulation. Even imperfect regulation can be shown to be more efficient than imperfect competition. Sensible, fair regulation will always trump incomplete or imperfect competition. Combining micro-managed regulation/competition and market impediments (*e.g.*, transmission bottlenecks, environmental restrictions, horizontal market power, etc.) could be even worse. Such actions would virtually always be less economically efficient than unbiased, albeit flawed by the human condition, traditional cost-of-service regulation practiced with diligence, intelligence, and integrity.

Q. WHAT DO YOU MEAN BY THE ACRONYM TANSTAAFL?

A. I mean that "There Ain't No Such Thing as a Free Lunch." One of my first remembrances as a kid was my Uncle Joe, the bartender. I remember free lunch served in his bar each Wednesday. I soon learned that the price of beer was bumped up each Wednesday (the 5-cent tap was not even available). I put "two and two" together and learned my first economic principle – TANSTAAFL!. The beer drinkers had to buy more beer and pay higher prices with bigger margins to get their not so free lunch.

In this context, merchant plants are a tempting option. Some have mistakenly called them "manna from heaven." My reaction is "not so fast." There are several reasons why I urge caution and am reminded that "manna," a biblical form of lunch bread, may not be free at all!

First, infra-marginal generation priced-to-market is a good deal, perhaps even a super normal deal for merchant plant owners. However, consumers will not find lower fuel adjustment or energy pass-through costs when they are forced to pay the same market price that existed before the merchant plant entered the market. Regulators, therefore, need to compare the higher margins anticipated by such infra-marginal sales priced-to-market clearing levels with the annual fixed cost recovery of cost-of-service regulation. Regulators also need to net against the fixed rate base recovery costs of such plants the fuel and efficiency savings that would also be passed on to regulated retail consumers under cost-of-service regulation if IOUs build and operate similar plants.

Second, regulated rates of return, depreciation, and cost-of-service pricing, in my experience, will probably result in lower costs than if similar plants are built by competitive merchants. Similar plants financed and built by competitive firms would confront quite different conditions relating to risk, business, financial and opportunity costs of capital. I will discuss this in more detail below.

Third, regulatory principles, such as "duty to serve," "native load priority," and "comprehensive state regulation" are not shallow phrases. They combine to explain that "merchant plants" may fly to other markets, and they may, without full or perfect competition, withhold supply to maximize profits. Self-interest and profit-maximizing under imperfect competition will not always yield the same short, intermediate, and long-term results as cost-of-service regulation.

Fourth, politically and practically, no regulated industry is ever deregulated unless there is excess capacity. To do otherwise (e.g. deregulate when there are shortages) would cause prices to go up.

Q. WHY DOES COMPETITION WORK BEST FOR CONSUMERS WHEN SUPPLY EXCEEDS DEMAND?

A. Virtually all political decisions to restructure regulated industries to competitive markets have occurred when supply exceeds demand; and/or new technologies (future supply) are available that would cause the same excess supply and lower price result. Restructuring and competitive choice in electricity markets are no different. If lower prices are the goal, and they always are for deregulators, the reform process needs (1) more supply than demand; (2) new entry with lower cost technology; and, (3) no market power, either vertical or horizontal.

When supply exceeds demand, competition pushes down consumer prices. When more efficient entry accompanies competition, there is additional pressure for market-clearing prices to decline and benefit retail consumers.

When demand exceeds supply, new entrants that are more efficient may back down or push out less efficient competitive suppliers some of the time. However, if the excess demand conditions prevail and/or the new entrant is infra-marginal, consumers will not experience lower prices because prices would increase. New entrants will simply earn high margins and consumers could pay more.

If additional new entrants are also restricted from free entry, the first entrants will reap the benefits of imperfect competition and achieve monopoly power in the form of higher margins, profits, and economic rents when they price to market and enter infra-marginally. These "first-in" merchant plants would be better off if they can maintain their beneficial initial position and additional new supply is not added. This results because excess demand (or short-supply) benefits producers that are not regulated at the expense of consumers.

A regulatory policy that encourages both "least cost" and "least price" when these concepts conflict works best when supply is short relative to demand. Regardless, few politicians are brave enough to deregulate when supply is tight. The only imaginable circumstance would be when, "but for" deregulation, there would be insufficient incumbent investment to expand supply and/or to capture the efficiency improvements of new technology. These exceptions are not relevant for Florida. I mostly find them in third world nations. I find that in the regulated electric industry found in Florida, an incumbent IOU could build the proposed plant more economically than could the petitioner. I also find that a profitable merchant investment is not necessarily good for consumers, and I do not know any other kind that are concerned with least cost/prices.

Q. HOW CAN COST-OF-SERVICE REGULATION BE LESS COSTLY THAN MERCHANT PLANTS WHEN THE INCUMBENT AND NEW ENTRANT WOULD BUILD THE SAME PLANT, IN THE SAME LOCATION, AND OPERATE IT SIMILARLY?

A. I previously explained that, in the merchant plant price-to-market world, "least cost" may not result in the "least price" for consumers. Under cost-of-service regulation, there is no such dichotomy between low costs and low prices because regulation ensures that lower costs flow through to consumers in lower prices.

Aggressive competitors and perfect competition would work to do the same thing. However, as I understand the OGC application, a merchant plant would enter infra-marginally and price to market, not to cost-of-service. There would not be any form of bidding or near perfectly competitive wholesale power market in Florida. It is possible, although doubtful, that the extra margins (*i.e.*, price minus AVC) earned by the merchant would just equal the rate base cost recovery assigned to a similar plant constructed by incumbent IOUs. It is more likely that in such a scenario, the margins earned by the merchant plant would exceed the incumbent's rate base recovery for a similar plant. And, without full competition, merchant plant owners would earn super normal profits.

Q. WHY WOULDN'T YOU EXPECT MERCHANT PLANTS AND IOUs TO PRODUCE SIMILAR CONSUMER PRICES?

A. I have prepared Exhibit CJC-2 to illustrate some important aspects of the differences between regulated IOU cost-of-service pricing and possible merchant plant investment and business strategy.

In my experience, there are at least three differences between these two circumstances, holding everything else such as cost, technology, fuel, etc. constant. These are:

(1) Weighted Average Cost of Capital (WACC), or opportunity costs, are likely greater for merchant plants than for IOUs. Currently, I find most IOUs expect to earn a weighted average rate of return of about 10 percent after taxes on rate base. I expect that "competitive" merchant plants would, by comparison, seek something in the 12 to 14 percent rate of return on their investment. In any event, their hurdle rates would be greater.

(2) Regulators would time the recovery of generation differently. Under cost-of-service regulation, regulators would allow the IOUs to recover the plant's cost over a 30 to 40-year time period. Merchant plant owners would not be so patient and would seek a shorter payback period. In Exhibit CJC-2, I consider two payback scenarios, 20 years and 10 years, for merchant plants.

(3) Regulation would also require straight-line depreciation for ratemaking purposes. This means higher revenue requirements up-front, constant annual depreciation, and declining regulated prices as rate base declines. Merchant plants would more likely be financed using an amortization schedule with constant annual capital recovery matched to annual revenue and income targets. This is *called sinking fund depreciation.*

Both cost recovery methods yield the identical recovery "of" the initial investment. They can also be structured to yield identical net present values of the capital charges assigned to each year. Nevertheless, Exhibit CJC-2 shows that these three differences combine to yield substantially higher annual prices and fixed costs (*i.e.*, revenue requirements) for merchant plants than for rate base plants with identical capital (or investment) costs and capacity.

For example, the highest costs allocated with a 30-year life, 10 percent ROR, and straight-line depreciation under rate base regulation in Year 1, would require a pre-tax charge of $25,333,333 (see page 1 of Exhibit CJC-2). These costs decline to $6,966,667 in Year 30. The lowest cost annual pre-tax revenue target for a merchant plant (namely 20 years amortization and 12 percent WACC or ROR) is the same each year, $25,436,968 (see page 5 of Exhibit CJC-2). The merchant would target this annual amount each year for 20 years. Therefore, even if merchants set "normal" returns at 12 percent, "normal" paybacks of 20 years would yield prices well above cost of service levels every year.

Quite obviously, regulated plants and merchant plants are not financed with similar expectations, even when they cost the same and operate similarly. Regulation is not flawless. However, lower prices will result, other things equal, under cost-of-service regulation.

Petitioners propose to allow a merchant plant to enter and sell into a regulated cost-of-service world. This is not competition. It is imperfect competition and new merchants are given significant market power that would not be checked by competition. Regulators should not allow this to happen. Supply needs to exceed demand in order to push down margins. Further, cream skimming price-to-market merchants cannot be permitted to soak up rents that neither perfect competition nor cost-of-service regulation would or should condone. These all need to combine to extend the payback for competitive merchants beyond 30 years and/or reduce returns below 10 percent.

Q. HAVE YOU PERFORMED AN ANALYSIS TO DETERMINE THE REASONABLENESS OF THE PROFIT TARGETS USED IN YOUR EXHIBITS FOR THE OGC MERCHANT PLANT?

A. Yes. In comparing OGC's cost recovery as a regulated cost of service plant versus what a merchant plant would require, I made three assumptions. Specifically, I assumed a 14 percent required return, a 20-year life and sinking fund depreciation, or amortization for a new merchant plant.

Based on this analysis and these assumptions, I estimated that merchant plant owners would seek about $28,687,340 in annual profits or net income from the plant. I have performed a second analysis to check the reasonableness of these assumptions and pricing results. I base this analysis on the information contained in Dr. Nesbitt's supply stack exhibits and annual load duration curves for the Florida Peninsula.

This analysis is contained in Exhibit CJC-3. First, I simplify Dr. Nesbitt's load duration curves and divide the year into base and intermediate load, with running costs in Florida ranging from $20 per MWh to $27.50 per MWh. This represents 83 percent of the dispatch hours in the year. I then assume that peak hours would approximately be the other 10 percent of the hours in which OGC would operate. The running costs for the plants that are likely to operate during peak hours would likely range from $27.50 per MWh to $50 per MWh during this period.

Q. WHAT DO YOU THEN DO IN EXHIBIT CJC-3?

A. In this Exhibit, I calculate what OGC's margin and projected income would be, given its running cost of $19 per MWh and its projected output of 4,480,740 MWhs. I find that these combine to yield a projected income of $28.51 million, which is essentially the annual amount I estimated in CJC-2 for a merchant plant seeking a 14 percent rate of return after taxes for 20 years, using sinking fund depreciation. I show this in Exhibit CJC-3.

Q. WHAT DOES THIS MEAN?

A. This analysis shows that OGC owners could expect to earn 14 percent and to recover their investment over 20 years with little risk. Additionally, after 20 years, all the initial capital expenditures would have been recovered. Consequently, margins earned would increase shareholder value.

Q. AT PAGE 104 OF HIS PREFILED DIRECT TESTIMONY, DR. NESBITT STATES THAT "OGC INDUCES THESE SAVINGS WHILE ACHIEVING A PRODUCTION MARGIN NEARLY TWICE THE VALUE REQUIRED TO JUSTIFY THE PROJECT FINANCIALLY." PLEASE COMMENT ON THIS STATEMENT.

A. This statement by Dr. Nesbitt confirms the fact that he thinks that the plant's owners expect to sell OGC's output at about $32 per MWh, 93 percent of the hours in the year. As I showed above, using some reasonable investor expectations regarding a 14 percent return and a 20-year capital recovery period, OGC would need to collect about $28.5 million per year more than its operating cost in order to achieve their target return. Dr. Nesbitt assumes that the plant would have running costs of $19 per MWh and that a market price of $32 per MWh would prevail on average in each hour of the year. OGC would, therefore, have an operating margin of $13 per MWh. Applied to the 4,480,740 MWh that the plant is projected to sell, the annual operating income would be about $58 million, about twice the amount I estimated the plant owners would require with a 14 percent return and 20 year payback. Assuming Dr. Nesbitt has reasonably estimated market prices, this plant would be an *extraordinarily profitable* investment for the owners under Dr. Nesbitt's assumed conditions in which OGC is priced to market (average of $32 per MWh and with running costs of $19 per MWh). And, this also shows that Dr. Nesbitt's alleged price suppression effects from selling at $19 per MWh will never materialize because the plant's owners, without competitive pressure, would price to market at $32 per MWh according to Dr. Nesbitt and the applicant's proposal. As I noted earlier, I will explain later in my testimony why I think that Dr. Nesbitt has overstated the likely market clearing price and, therefore, his claimed benefits.

Q. WHAT DO YOU MEAN BY "CREAM SKIMMING" WHEN YOU REFER TO "INFRA-MARGINAL PLANTS PRICED-TO-MARKET" EXPECTING SUPRA OR ABOVE MARGINAL PROFITS?

A. Suppose the identical generating plant could be built by either a merchant owner or an IOU. Furthermore, let us assume the same heat rates, fuel contracts and prices, operating and maintenance costs, and identical availability factors and place in the dispatch stack. In short, everything is identical, except the means by which owners or investors price their output to recover their investment and earn income.

An IOU that builds a rate base plant under cost-of-service regulation faces some risk of investment cost disallowance; cost recovery is spread over 30 to 40 years; and, there is no upside if the generating station beats other energy and fuel prices, yielding fuel savings and lower marginal costs than other generating stations.

A merchant plant sells its output to a centrally-dispatched entity, presumably making its sales based upon its system lambda (*i.e.*, location adjusted short-run marginal (running) costs) and is paid the price that clears the market. There is no cap on the merchant plant's upside in terms of how much annual income the merchant earns.

A merchant plant's annual operating income equals the sum of the operating margins (roughly weighted average generating price ($\overline{P}$) minus AVC times output measured in MWhs). An IOU passes through to its customers operating costs. Thus, IOU operating margins are effectively zero. Merchant plants use their earned operating margins to recover their investment costs and earn income. IOUs use their regulated return on rate base to do the same thing.

Investors generally trade off risk and return. This means that investments with higher risks require higher expected returns, and vice versa. The Petitioner seems to want higher returns. However, there is no real risk under the "price to market" conditions contemplated by this petition. Consequently, OGC would earn super normal profits with virtually no risk.

Regulators seeking to hold prices to the lowest, while still "just and reasonable" levels, should attempt to set prices based on costs of service. Project sponsors are disingenuous when they falsely claim that merchant plants are "win-win." The OGC petition obfuscates the fact that they plan to price to market, not to cost, with well-placed distortions that strike useful chords (saves energy, better for clean air, free lunch, etc.) In fact, by claiming competition is the result, merchants that build in Florida and price to market would have no economic interest in expanded competition coming to Florida, once they build. They would prefer to sit in the middle of the stack, operate most of the year without competitive risk, and receive prices and income based upon older, less efficient units establishing a "regulated," not a competitive price.

Priced-to-market, infra-marginal plants with no competitive risk or pressure are simply "cream skimming" the market. Their claims are meant to deceive regulators. And, we need to ask: "what market?"

Q. WHY DO YOU THINK THAT REGULATORS AND INVESTORS NEED TO BE "FORWARD" LOOKING NOT "BACKWARD" OR EVEN "CURRENT" LOOKING IN THE WAY THEY ANALYZE A GENERATING STATION'S POTENTIAL VALUE?

A. Power stations come on line and supply additional capacity. If they are combined-cycle units, or intermediate size, they will also generally displace less efficient units, thereby reducing operating costs over the course of the year.

Proponents of merchant plants point to these expected fuel, heat-rate, environmental, and other efficiency gains. These are probably valid claims. However, such statements are potentially very misleading because at least two factors can, with virtual dead-on certainty, work to reduce the economic value of these "new" power stations over the course of their life.

These factors are as follows. First, a new plant comes on line after a "teething" period, expecting to perform at a "best in its class" level, thereby achieving very high capacity factors. As these new generating stations age, "newer" stations would come on line and are expected to displace the former "best in class" units. It is typical, especially in large electric markets such as Florida and the Southeastern Electricity Reliability Council (SERC), for units to experience declining capacity factors over their operating or economic life. This life-cycle expectation is virtually ubiquitous across the world and over time for power stations.

Second, technology does not stand still. Newer stations built in the future will incorporate the best of what we now know, as well as what we learn and can reasonably use by the time these future plants are added to a region's or market's generation portfolio or mix.

Q. WHY ARE THESE TWO FACTORS IMPORTANT FOR EVALUATING A NEW MERCHANT PLANT'S CONTRIBUTION TO FLORIDA?

A. Any new plant will compete over its life with what we have in the future, not what we have at the time it is built. My first major effort in explaining electricity economics to regulators was on this very point thirty years ago. Indeed, I explained that the NPV of "new" generating stations is always less than it appears when it first enters the dispatch stack. Both declining capacity factors and technological advances effectively increase the discount factors that determine a new merchant plant's NPV. Increased discount factors reduce the plant's NPV.

These conclusions pertain, regardless of ownership. If there are differences between a merchant plant and an incumbent IOU owned plant, they are probably related to the operating life and time period of cost recovery used for plants built under rate base regulation. Merchant plant owners seek a higher payback and higher return. These realities both mean that merchant plant owners want higher prices than IOUs would expect to be allowed from regulation. Other differences also, as explained elsewhere in my testimony, affect NPV.

The FRCC has identified a need for new plants in Florida and the utilities that comprise the FRCC have proposed plans to build new plants to meet this need. There is simply no need to overstate the value of a new generating station in Florida. Eventually, all new plants are displaced and progressively moved off the generation dispatch stack and retired. Florida most likely "needs" new combined-cycle natural gas fired power stations. The regulatory questions are how much do you want to pay to get them and how soon do you want to pay them off. There are "no free lunches" or "manna from heaven."

Any implication that Florida needs this merchant plant to get caught up to the rest of the country with regard to competition is simply not correct. The states that have undergone restructuring have done so because regulation was generally perceived not to be working in their jurisdiction and they were seeking new, lower priced alternatives. Florida has an effective functioning market that is working to get lower energy prices. There is little need to "fix" that which is not broken, especially when that "fix," most likely, will result in higher prices for small retail customers.

Q. WHAT DOES THE RESTRUCTURING TAKING PLACE AROUND THE NATION HAVE TO DO WITH MERCHANT PLANT ENTRY IN FLORIDA?

A. One of the most important things to glean from the restructuring that is underway in several states across the country is that the restructuring process is extremely complicated and fraught with many thorny issues. If the Florida Legislature and this Commission decide to proceed with restructuring the electric industry in Florida, there are many things that need to be done to protect consumers who currently benefit from cost-of-service regulation in the form of lower prices than they might pay under competition. I am not anti-competition. To the contrary, I support competition when all consumers are "winners". However, when it is likely that some current consumers could pay more under restructuring, I urge state regulators to take a more cautious, go-slow approach.

The national utility restructuring attempts to do several things. First, proponents of restructuring seek to remove transmission bottlenecks and form independent transmission entities (regional transmission organizations) to achieve reliability and access without discrimination. Second, proponents of restructuring seek to form or encourage wholesale markets that are sized so as to reduce any potential horizontal market power. Third, proponents of restructuring seek to form new entities and regulatory structures to achieve and police the first two objectives. Fourth, proponents of restructuring want customer choice to evolve to new products, new suppliers, and retail choice.

Florida regulators and legislators are aware of all this activity. Florida also sits on the edge of a low-cost/low-price region that understandably wishes to go slow in order for restructuring to produce consumer benefits, not higher prices. I have little doubt that change is coming throughout the nation. Nevertheless, lower-priced and transmission-congested regions are different from the areas that have gone through, or are currently, restructuring.

A particular aspect of this difference is that the states that are restructuring generally contemplate a transition period in which incumbent utilities offer a "price to beat," or guaranteed, retail rate cap. This approach means that all actions that lower "cost of service" prices today will be available to consumers during the transition period. New IOU rate base investment in combined cycle natural gas fired stations in Florida would do this, but merchant plants would not under current circumstances in Florida.

For efficient competition to emerge, many steps must be undertaken within a comprehensive policy setting arena. This needs to occur before the existing regulatory structure is altered. A state cannot hope to jumpstart the competitive market or restructuring process by simply dropping a merchant plant into a regulated cost-of-service world. Merchant plants are either irrelevant to the main stream of a very complex restructuring process and regulation's principal consumer protection purpose, or, worse, they mistakenly take the regulatory eye off the restructuring process. Merchant plants are not competitive outcomes. They do not advance market competition or customer choice. And, they would likely increase prices for consumers.

Restructuring is about "gives" and "gets." It is potentially disruptive and costly to insert a new stakeholder into the process when incumbent relationships are untangled. Worse, incumbent utilities should not be weakened under the old rules before the restructuring process starts in Florida. Starting with a level and fair playing field will make any transition less costly. Regulators would seek reliability and lower prices under traditional, transitional and competitive regulation. The regulatory and economic objectives are always the same: low prices and customer service.

I fail to see how new merchant plants help consumers or regulators under either cost-of-service regulation or competitive restructuring in Florida.

Q. AT PAGES 31-32 OF HIS TESTIMONY, DR. NESBITT IDENTIFIES MERCHANT PLANTS THAT WERE OPERATIONAL AS OF MAY 25, 1999. PLEASE COMMENT ON DR. NESBITT'S LIST.

A. Dr. Nesbitt includes 32 plants in his list. Sixteen are located in California, a state that has undergone restructuring and a state that required its three IOUs to divest their fossil fuel fired plants. Similarly, 11 of the remaining 16 merchant plants in Dr. Nesbitt's list are located in states that have passed restructuring legislation and/or are actively undergoing restructuring. Similarly 14 of the 16 merchant plants that Dr. Nesbitt identifies as under construction are located in states that are undergoing restructuring. Most of these states had very high-priced electricity. In those states, a political decision was made to give up on the existing cost-of-service regulation, which was correctly perceived to be broken in these states.

Q. WHAT, IF ANYTHING, CAN REGULATORS DO TO CAUSE IOUs TO ACHIEVE MERCHANT PLANT PERFORMANCE?

A. Merchant plants have strong incentives to maximize profits. Under perfect competition, there are price-takers, and merchant plant owners would attempt to maximize plant availability factors or sales.

Generating stations that are a similar type and vintage as merchant plants can also be encouraged to achieve similar operating and availability factor performance. In fact, cost-of-service ratemaking has been enhanced in a number of jurisdictions and industries through incentives.

Specifically, cost-of-service ratemaking can be amended with incentives to share the benefits of above-target output or availability performance between shareholders and consumers of regulated services. Generally, cost-of-service regulation that is amended with incentives is less costly for consumers than "priced-to-market" infra-marginal merchant plants would prove to be. Performance incentives can yield outcomes similar to the perfectly competitive market that does not exist in Florida.

Florida does not have immediate plans for wholesale power markets that approach perfect competition. Therefore, at least for the short and intermediate terms, cost-of-service/rate base treatment utilizing incentives would be better for consumers in Florida than merchant plants that enter most likely contemplating "cream skimming" strategies.

Q. HOW WOULD ANY MERCHANT PLANT OWNERS' INTENTIONS TO CONVERT THEIR UNITS TO PLANTS ENGAGED IN LONG-TERM CONTRACTUAL SALES AFFECT THE VALUE OF MERCHANT PLANTS RELATIVE TO RATE BASE TREATMENT FOR SIMILAR GENERATING STATIONS?

A. If merchant plants are used to make long-term sales to incumbent utility companies, these contracts effectively become very similar to qualifying facility (QF) contracts. The specific "take" and "pricing to or above market" terms matter. Regardless, long-term power contracts between merchant plant owners and incumbent IOUs would mean that the merchant plant owners could, and would, effectively lean on the IOUs' balance sheets. I would, therefore, expect the merchant plant owners to capitalize these very certain cash flow streams. This would permit the owners to leverage these gains, perhaps elsewhere in the world or in other businesses.

There is nothing unsavory about such business leverage practices. However, Florida regulators need to be relatively certain that there are merchant plant benefits that otherwise could not be achieved under traditional cost-of-service regulation, incentive modifications, or some "third way." Regardless, before regulators support plans that cause merchant owners to act like IOUs and engage in long-term contractual sales back to IOUs, regulators need to question why they do not simply order the incumbent IOU to do the same thing -- keep consumer prices down.

If competition and the efficiency gains of competitive markets are the goal, regulators should recognize that "priced-to-market," infra-marginal merchant plants, with or without sales contracts, are not competitive outcomes. At best, they represent "high-priced" experiments to prove that generation is not a natural monopoly. But, we already know this, and that information is freely available.

SECTION III: A CRITIQUE OF DR. NESBITT'S CLAIMED SAVINGS

Q. WHAT ARE YOUR VIEWS CONCERNING DR. NESBITT'S SIMULATION MODELS?

A. I have two primary opinions. First, no model is better than the data and assumptions used to run it. Dr. Nesbitt's assumptions are very misleading. Second, common sense should make it apparent that the results from his model are not reasonable.

Q. CAN YOU PROVIDE AN EXAMPLE OF BAD OR MISLEADING ASSUMPTIONS PRODUCING AN UNREASONABLE RESULT?

A. Yes. First, I recall a rather dull story I have recounted so often that I can no longer even remember how much is accurate. Regardless, many years ago, I told my son that if he walked home from school, I would pay him the money he saved on public transit. I knew buses cost about 50 cents. Thus, my maximum exposure was $2.50 per week. After a week, I asked him how much I owed him. He said about $50.00. I was taken aback because this was 20 times what I knew it could reasonably be. Upon questioning his math, he told me that he walked home five days, avoiding the $10 cost of a taxicab and the appropriate tip each day. So, we talked about least cost and reasonable alternatives. I paid him $2.50, and complimented him for his cleverness and nice try.

Dr. Nesbitt has done something very similar. He assumes that OGC's owners would sell their output, some 4.48 million MWh per year, "priced to market." He also assumes a vigorous competitive wholesale market that does not exist. If such a market existed, it might price OGC's output at close to $19.00 per MWh. This is not an insignificant assumption. In fact, OGC proposes to price its output to market and sell at about $32.00 per MWh, not $19.00 per MWh. Assuming that a competitive wholesale market for OGC's output exists when no such market actually exists is as unreasonable as a sixth grader taking a $10 taxi ride home from school when 50 cents-per-ride buses run often.

To elaborate further, Dr. Nesbitt concludes that the annual savings achieved if OGC sells at $19.00 per MWh (which it does not propose to do) would be about $179,540,000 per year, or just about what the plant would cost (about $190,000,000) to build. Wow! Back when my son claimed I owed him $50 for one week, a good used car cost $2000, or 40 weeks times $50. If I gave my son a car, he would save enough taxicab fees to pay for it in a year. My arithmetic and logic then, as well as my logic and reasonableness now, make it very apparent that Dr. Nesbitt is way off the mark.

Q. HAVE YOU PERFORMED ANY CALCULATIONS TO DEMONSTRATE DR. NESBITT'S ERRORS?

A. Yes. First, I note that he observes that OGC is "infra-marginal". This means that it will reduce average cost but not affect the marginal cost or price. OGC would be paid the marginal plant's cost, which Dr. Nesbitt assumes is about $32.00 per MWh over the year. Thus, if prices do not change, there would be no price suppression benefits. Certainly, price suppression benefits would not approach or equal OGC's all-in investment.

Second, Dr. Nesbitt overstates and confuses both OGC's annual profit and consumer benefits for Floridians. Consider the $179,540,000 of annual price suppression savings that Dr. Nesbitt claims in his Revised Table 10, for the year 2004. Attributing nearly $180 million to OGC is misleading because OGC does not "save" this amount in the sense that this is OGC's margin. Dividing this "estimated" savings by one year of OGC output yields the per MWh margin or cost savings that Dr. Nesbitt implies. Therefore,

$$\text{Per MWh of Dr. Nesbitt's Savings} = \frac{\$179{,}540{,}000}{4{,}480{,}000 \text{ MWh}}$$

$$= \$40.08 \text{ per MWh}$$

Thus, Dr. Nesbitt's calculations imply an OGC margin over the entire year of about $40 per MWh. Adding this margin to OGC's estimated running or operating costs of about $19 per MWh shown on Dr. Nesbitt's Exhibit 5 for the Florida Supply Stack, yields a marginal cost, price-to-market displaced price of $59 per MWh all hours of the year.

However, there are several facts that demonstrate that Dr. Nesbitt's suggestions are off the mark. For example, Dr. Nesbitt's supply stack and other exhibits show that a $50 per MWh price would occur less than 1 percent of the hours, not nearly the 100 percent he needs to get his calculated savings. Further, the $59 per MWh price implied by his analysis would virtually never occur; just as my son would virtually never take a taxi home from school. And, in order for Dr. Nesbitt's calculations to work, this non-existent $59 per MWh price would need to be displaced all year, or about 8760 hours; just as my son would have to plan to ride a taxi home from school every day in order to justify purchasing a $2000 second car for a sixth grader. Dr. Nesbitt's calculations simply make no sense.

Q. IS THERE ANYTHING ELSE WRONG WITH DR. NESBITT'S ANALYSIS?

A. Yes. The OGC proposal does not plan to pass its operating margins (price minus cost savings) on to retail customers. Dr. Nesbitt, on the one hand, assumes that vigorous wholesale competition would eat away at OGC's margins, drawing the price down to OGC's marginal cost of $19.00 per MWh. However, OGC is only about 500 MWs in a 40,000 MW system, or about 1.25 percent of the available capacity in Florida. All other units are dispatched on a system lambda basis. Retail customers pay no margins above these regulated plants' operating or running costs.

OGC would be the proposed exception. The OGC petition proposes allowing OGC to price to market. Thus, retail customers would pay as much as $50 per MWh, or whatever, when OGC runs at about $19 per MWh. Therefore, Dr. Nesbitt's competitive assumptions are contrary to Florida regulation, which already captures all the operating savings from a rate base or IOU plant in exchange for rate base fixed cost recovery on all such infra-marginal plants.

Q. IF DR. NESBITT'S ANALYSIS WERE CORRECT, WHAT WOULD THIS MEAN FOR FLORIDA REGULATORS?

A. If a new plant costs about the same to build and own as the annual energy cost or retail price savings, regulators should require incumbent utilities to build such plants and pay them off (i.e., expense them) in one year. After that, they would be "manna from heaven" and "free lunches" and customers would not have to pay any fixed charges or "price to market" prices.

OGC's output will not be priced at its running cost of $19 per MWh. And, OGC's output will not replace $59 per MWh electricity 8,760 hours in the year because the annual average price to market is, according to Dr. Nesbitt, about $32 per MWh, not $59 per MWh. Thus, consumers would not receive any savings under the OGC petition since the $32 per MWh price for electricity they pay after OGC would enter the market is the same $32 per MWh Florida customers currently pay.

This is not an example of "manna". This is not a "free lunch". Combined cycle natural gas-fired plants may be sensible choices for Florida. How to pay for them, who should own them, and whether they should be placed into a cost-of-service rate base and centrally dispatched are still important regulatory questions.

Accordingly, it is unfortunately not possible to invest $190 million and recover it entirely in one year, or to expect it to yield more than $750 million of NPV savings over ten years. And, there is no way this can happen if the plant's output is priced-to-market at about $32.00 per MWh, or more, as Dr. Nesbitt assumes.

Dr. Nesbitt's results are based upon a $19.00 per MWh price that will not be used by OGC and price suppression effects that will not occur in the supply stacks. His results are bogus, unreasonable and should be given *short shrift* by regulators.

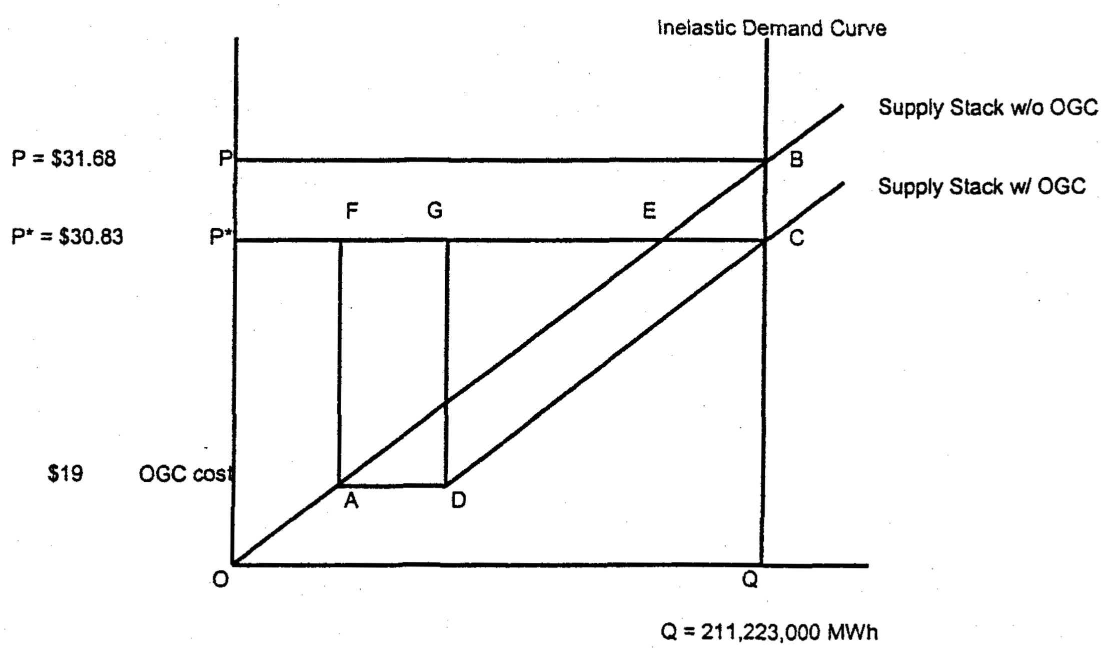
Q. HOW DOES DR. NESBITT CLAIMS A $0.85 PER MWh SAVINGS IN THE FIRST YEAR FROM THE OGC PLANT?

A. Dr. Nesbitt states that without OGC, the average electricity price would be $31.68 per MWh. He also shows OGC with a running cost of $19 per MWh in his stacking exhibits. He effectively assumes, contrary to OGC's petition, that OGC would be priced at its running costs and would shift the entire supply curve to the right, causing all prices to fall on average $0.85 per MWh for every MWh produced in the Florida Penninsula for the entire year. This is not what the OGC petition, in fact, proposes to do, and Dr. Nesbitt's claimed savings of nearly $180 million per year are completely false. Instead, the OGC plant would be "priced" at the assumed market clearing price of about $32 per MWh, or at just enough of a discount to dispatch the plant, for each of the nearly 8760 hours in the year it is expected to run. Therefore, consumers would not realize lower prices because OGC does not propose to charge its running cost.

Q. WHY ARE THE CLAIMED $180 MILLION IN SAVINGS FALSE?

A. There are two analyses that demonstrate the serious flaws in Dr. Nesbitt's false claim of $180 million in annual savings for consumers. First, consider the diagram in Figure CJC-2.

Figure CJC-2



The rectangle PBCP* appears to be how Dr. Nesbitt calculates benefits of $180 million per year. He assumes that demand is totally inelastic, hence the demand function in Figure CJC-2, represented by the vertical line Q. Dr. Nesbitt also assumes that the supply schedule would shift to the right, lowering the market clearing price in every hour from P to P*, or an average hourly price reduction of $0.85 per MWh. The totally inelastic demand schedule significantly exaggerates this claim.[2] His analysis also assumes that OGC would sell its output into the current economic dispatch at $19.00 per MWh. This is not what OGC proposes.

OGC would price to market essentially selling electricity at \$31.68 per MWh. Accordingly, ratepayers would not receive the average per MWh reduction of \$0.85 per MWh contemplated in Dr. Nesbitt's analysis.

This is not Dr. Nesbitt's most serious mischief. Dr. Nesbitt also uses this impossible percent price reduction to determine his approximate Ratepayer Savings by multiplying \$0.85 per MWh by the entire output of all generators in the Florida Peninsula, as follows:

\$31.68 - \$30.83 = \$0.85

\$0.85 per MWh * 211,223,000 MWh = \$180 million

This is simply not correct. Florida consumers would not receive the \$0.85 per MWh reduction over their entire annual output because OGC does not propose to pass on its operating margin to consumers under current regulation. Furthermore, there is no competitive retail market in Florida that would allow Dr. Nesbitt to assume falsely that OGC would be forced by competition to sell its output at \$19.00 per MWh versus its price to market "proposal", which would yield OGC a price close to \$31.68 per MWh. Consequently, his claimed annual savings of \$180 million are similarly non-existent.

Q. WHAT IS DR. NESBITT'S NEXT ERROR?

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[2] If the demand curve is drawn to show an elastic demand, which is more likely than an inelastic demand, the demand curve will be downward sloping, as opposed to the vertical line drawn by Dr. Nesbitt. The point at which the supply stack with OGC intersects an elastic demand curve would necessarily occur at a price higher than where the same supply stack intersects Dr. Nesbitt's inelastic demand curve. Thus, the price differential would be lower than that claimed by Dr. Nesbitt if a more appropriate elastic demand curve was used.

A. Dr. Nesbitt's second error is more serious. In addition to failing to recognize the market that currently exists in Florida, Dr. Nesbitt fails to address the reality of the OGC Petition. Figure CJC-2 can be used to understand how small the ratepayer benefit would actually be even if we use Dr. Nesbitt's totally inelastic demand schedule and assume his $0.85 per MWh average price reduction is correct.

Societal net benefits would not conceptually equal Dr. Nesbitt's rectangle (PBCP*). Instead, Societal net benefits in Florida would be represented by the trapezoid ABCD. This trapezoid represents the increase in consumers' and producers' surplus from a shift in marginal production costs under Dr. Nesbitt's unreasonable assumptions. Thus, Florida consumers and producers would experience, under Dr. Nesbitt's biased assumption, a gain of combined consumers' and producers' surplus equal to the trapezoid ABCD. This is clearly smaller than rectangle PBCP*.

Most of this gain would go to OGC leaving very little for all others in Florida. Consider rectangle AFGD in Figure CJC-2. This is OGC's expected profit at the lower market clearing price of P*, output AD, and a running cost of $19 per MWh. Rectangle AFGD, OGC's profit, is mathematically equal to the parallelogram AECD. This is because the rectangle and parallelogram share the same base AD and the same height GD. Therefore, most of the cost "savings" actually go to pay for OGC's profit

Q. IS ANYTHING LEFT FOR OTHERS IN FLORIDA?

A. After deducting OGC's profit and running costs, Florida consumers would receive the residual benefit represented by triangle EBC, since this triangle is formed by subtracting OGC's profits from the trapezoid ABCD.

ABCD – AFGD = ABCD – AECD = EBC

Q. CAN YOU DETERMINE HOW MUCH OF A BENEFIT THIS IS?

A. Yes. It is possible to determine the size of this benefit for Floridians excluding OGC's profits. This is possible because the area of triangle EBC is:

ΔEBC = ½($0.85 per MWh * 4,480,000) = $1.9 million.

Thus, the benefit to Florida consumers after extracting OGC's profits (represented by AFGD) is not $180 million per year as implied by Dr. Nesbitt. Rather the benefit to others in Florida (not OGC) is actually only about one percent of that claim, or $1.9 million per year. Thus,

- Social benefits do not equal $180 million per year.
- Out of state owners of OGC would earn significant profits.
- Using Dr. Nesbitt's biased assumptions, benefits for others in Florida would only be about $1.9 million per year, which is far less than the savings that would be produced by a similar plant built by an incumbent investor owned utility.

Q. WHAT IS THE SECOND ANALYSIS THAT DEMONSTRATES DR. NESBITT'S MISLEADING AND BIASED CONCLUSIONS ABOUT CONSUMER BENEFITS?

A. In order to reduce the average retail price as much as Dr. Nesbitt claims, the OGC plant would need to make up 6.67 percent of the Florida market. However, it would make up only 2.12 percent[3] of the MWhs sold in Florida. Dr. Nesbitt's conclusions make no mathematical sense. I show this below. Dr. Nesbitt claims his model would reduce the average price for all Florida MWhs, or some 211.223 million MWh from $31.68 per MWh to $30.83 per MWh. He also suggests that his model priced OGC at its marginal cost, or $19.00 per MWh. Although this is contrary to what the petition states at pages 24 and 27, let's assume that this is true. I asked myself what it would take to move the average price from $31.68 per MWh to $30.83 per MWh (i.e., an 85¢ per MWh reduction), assuming one unit such as OGC was added to Florida at $19.00 per MWh.

I used interpolation and calculated the following:

(1) $30.83 = $31.68 (1-X) + $19 (X)

(2) $30.83 = $31.68 - $31.68X + $19X

(3) .85 = 12.68X

(4) x = 6.67

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[3] Note that while OGC would make up about 1.25 percent of the available capacity in Florida (see page 58), it would make up 2.12 percent of the MWhs actually sold in Florida. The difference results from OGC's initially higher than average availability factor (i.e., its utilization rate).

The previous calculation shows that OGC would need to equal 6.67 percent of the output in Florida, if its introduction to the supply stack in Florida at $19.00 was to pull the average price from $31.68 to $30.83.

Dr. Nesbitt made two errors here. First, the calculation shown above assumes OGC is paid its running cost just like all regulated units in Florida that the IOUs centrally dispatch. However, Dr. Nesbitt and OGC describe how, unlike rate base generation, OGC would monetize its margins to provide a return "on" and "of" capital to its owners. This means that OGC, by pricing to market, would charge an average price essentially equal to $31.68 per MWh, based on Dr. Nesbitt's assumed average price. The difference between this price and its $19.00 per MWh running cost represents OGC's average hourly margin of $12.68 ($31.68 - $19.00). Such an arrangement would leave little or no room for any retail price reduction; and certainly not the falsely claimed $0.85 per MWh reduction that would only materialize if OGC could more than triple its output (which is physically impossible) and sell at $19.00 per MWh (which is not what OGC proposes to do).

Second, the OGC output is projected to be 4.48 million MWh at a high 93 percent capacity factor. Dividing OGC's output by Dr. Nesbitt's estimate of the Florida Peninsula's output of 211.2 million MWh shows that OGC would represent about 2.12 percent, not nearly the more than three times greater 6.67 percent of total output, shown in my calculation above. Additional output stimulation and/or displacement due to supply curve shifts would not be sufficient to overcome this gap. This is extremely important. If OGC constitutes 2.12 percent of the energy market (MWhs) when it runs at a 93 percent capacity factor, then it would need to run at a 292 percent capacity factor. In other words, in order for Dr. Nesbitt to be correct, OGC would need to run more than 25,000 hours each year out of a possible 8760 hours in a year. In other words, the OGC plant would need to run nine eight hour shifts per day! This is obviously impossible. Dr. Nesbitt's calculations are wrong!

Q. WHAT DO THESE CONCLUSIONS MEAN FOR DR. NESBITT'S CLAIM THAT OGC WILL YIELD $764 MILLION IN BENEFITS OVER TEN YEARS?

A. Since the price suppression benefits to consumers are insignificant or even negative, Dr. Nesbitt's NPV claim is utterly false and will not materialize in nearly three-fourths of a billion dollars in benefits for Florida consumers. Under the pricing terms set forth in the OGC petition and current circumstances, I suspect Florida's consumers would pay more, not less, if the OGC petition were approved.

Q. HAVE YOU CONSIDERED THE POSSIBILITY THAT DR. NESBITT MAY HAVE OVERESTIMATED THE AVERAGE ANNUAL HOURLY MARKET CLEARING PRICE OF ELECTRICITY IN HIS ANALYSIS OF THE FLORIDA PENINSULA ELECTRICITY MARKET?

A. Yes. Dr. Nesbitt has used an average annual market-clearing price for generation of $31.68 per MWh or about 3.2¢ per KWh. This price is about one third higher than the highest prices I have generally encountered in my analysis and consulting related to competitive electricity markets. Typically, I find the higher estimates to be about 2.5¢ per KWH, or $25 per MWh. I also have often found estimates as low as 1.8¢ per KWH, or $18 per MWh. The lower end of the estimates suggest Dr. Nesbitt's estimated average hourly prices could be more than 75% higher than what others around the nation are predicting and relying upon. Accordingly, my first reaction to Dr. Nesbitt's $32 per MWh estimate was that it most likely was not a competitive market clearing price. Up to this point in my analyses and discussion, I have nevertheless used this $32 per MWh price to explain why Dr. Nesbitt's conclusions and policy recommendations are fatally flawed.

Q. DID YOU PERFORM ANY QUANTITATIVE ANALYSES TO DETERMINE IF DR. NESBITT'S APPROXIMATELY $32 PER MWh PRICE WAS CONSISTENT WITH THE FACTS AND CIRCUMSTANCES IN FLORIDA?

A. Yes. Dr. Nesbitt relied upon FERC Form 714 load data. Therefore, I collected the FERC Form 714 data for three of Florida's IOUs from 1996 to 1998. These forms show the short-run marginal cost, which is called system lambda, essentially for each hour in the year. I also combined this information to calculate the average annual hourly price for Florida Power & Light (FPL), Florida

Power Company (FPC), and Tampa Electric Company (TECO) based upon a least cost dispatch for each company's system lambda. It is important to realize that the system lambda is the running cost of the most expensive to operate generation used by an IOU in any particular hour of the year.

In addition, I combined the FERC Form 714 hourly data for these three Florida Peninsula utility companies to determine a combined or joint least cost dispatch system lambda for the Florida Peninsula. I did this by selecting the highest running cost of each of these utility companies in each hour of the year because I assume these three companies would engage in joint least cost dispatch.

Q. WHAT DID YOU FIND IN THIS ANALYSIS?

A. The most recent year for which FERC Form 714 data is available is 1998. I think that this year should be given greater weight than previous years for predicting future prices and in reflecting current purchases.

In 1998, the average annual hourly system lambdas are as follows:

1998 AVERAGE HOURLY RUNNING COSTS

Of the Most Expensive Unit Dispatched (System Lambda)

($ Per MWh)

FPL	$20.30
FPC	$18.30
TECO	$15.91*

	($13.94)
Joint Dispatch	$21.14

*1998 data is not available. Therefore, I show 1997 data. In parentheses, I also show an estimate for 1998 after scaling the 1997 TECO data to match FPL and FPC's running cost.

Q. WHAT WOULD HAPPEN IF YOU USED THE TWO PREVIOUS YEARS IN YOUR ANALYSIS?

A. The average hourly system lambda's increase by about $3 per MWh for FPL and FPC. TECO's system lambdas are on average about $1 less in 1996 than 1997. The joint dispatch data for these three combined generating companies would also increase by about $3 per MWh for 1997 and about $4 per MWh for 1996.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. All three utility companies have average annual running costs at or below the approximate $25 per MWh "all-in" costs that I have generally been finding around the nation for a new, efficient combined cycle natural gas generating station. Further, Florida's unique geographic location at the end of the natural gas pipelines isolates it from natural gas supplies, driving up natural gas transportation costs. This is in turn, is likely to drive the "all-in" cost in Florida above the $25 per MWh price I often find nationally for a new combined-cycle plant. The "all-in" cost could perhaps go as high as $27 to $28 per MWh, but still much less than Dr. Nesbitt's $32 per MWh price. The IOUs actual average annual running costs suggest to me that these utility companies have been adding new capacity both to meet growth and to minimize the long-term present value of their system expansion costs. In other words, the Florida Peninsula investor owned electric utility companies have been using least cost planning, which takes into account minimizing operating costs and the present value of generation costs, to meet load growth.

Q. WHY DO THESE DATA AND ANALYSES SUGGEST THIS CONCLUSION TO YOU?

A. A utility that, for example, simply adds combustion turbines to meet increased demand would, on average over the hours in a year and over time, likely have higher average system lambdas than the "all-in" cost (i.e., average annual total costs) of an efficient new generating plant that could be built both to meet load growth and to minimize system costs over the life-cycle of that new plant. There are exceptions in the real world. However, the similarity between these average hourly system lambdas and the average total costs of new, efficient combined cycle plants suggests to me that the Florida Peninsula is currently essentially in a long-run planning equilibrium. Simply put, Florida regulation and utilities have been doing their combined job and meeting their collective responsibility for Florida's consumers. This is demonstrated by average hourly system lambdas that approximate the $25 per MWh that I often find used nationally as a benchmark price for new combined cycle natural gas-fired generation, and that beat the likely higher "all-in" cost of a new combined-cycle plant in Florida by as much as $2 to $3 per MWh.

Q. WHY DO YOU THINK THAT THE "ALL-IN COST" ESTIMATES FOR FLORIDA ARE ABOVE WHAT YOU GENERALLY FIND NATIONALLY?

A. Florida's weather and above average natural gas delivery costs are the most likely reasons for any differences. I have not, however, performed a detailed analysis. Nevertheless, I am very certain that Dr. Nesbitt's $32 per MWh "competitive" price estimates are too high for Florida.

Q. IS THIS THE END OF THE STORY?

A. No. The joint dispatch and FERC Form 714 data reflect the highest running cost of each unit owned and operated by these three utility companies in the Florida Peninsula. In addition, there are energy purchases that each utility makes over the course of the year.

Q. HAVE YOU ANALYZED UTILITY PURCHASES IN FLORIDA?

A. Yes. I also collected cost and quantity data for the purchases made by these three Florida utilities over the same time period from their respective FERC Form 1 filings. I segregated this data into purchases made from within Florida, as well as energy purchased from generators outside the state of Florida.

Q. WHY DID YOU MAKE A DISTINCTION BETWEEN ENERGY PURCHASED FROM WITHIN AND OUTSIDE FLORIDA?

A. Utility purchases from privately owned, customer owned, and governmentally owned utilities from within Florida typically cause lower retail or wholesale prices for the selling utility company's customers. Further, when TECO purchases electricity for a lower price and this reduces the retail prices that would have been paid by its customers, this is an unambiguous benefit for TECO's retail customers. This conclusion is true regardless of where the generation is physically located and who owns it.

There is, however, an important distinction. Suppose FPL sells TECO the energy that lowers prices below what retail customers otherwise would pay in Tampa. Suppose also that the price paid for the electricity includes both a demand or capacity charge and an energy charge. This effectively means that the full price TECO pays FPL exceeds FPL's running cost. The extra margin paid to FPL, a regulated Florida utility, is then typically used to reduce the prices paid by FPL's customers. This within state transaction is a "win" for TECO's ratepayers and a "win" for FPL's ratepayers. Joint economy dispatch or transactions would lower prices for both sets of retail customers in Florida. A similar set of mutual "wins" would also occur when a within state cooperative (customer owned utility) or a municipal utility is involved in similar transactions with IOUs in Florida.

Now, suppose that an unregulated merchant or an out-of-state marketing entity, (e.g. Southern Company) sells energy to TECO. There would be one round of Florida ratepayer benefit if TECO's prices continue to be less than they would otherwise be. However, the margins earned (i.e., energy prices above running costs,) would not reduce retail rates for other Florida retail or wholesale customers. Any such margins would instead be used to increase the net income of the merchant or out-of-state marketer. As matters of economic efficiency and the effect on retail rates in TECO, this distinction would scarcely matter. However, regulators should, and in my experience generally do, recognize the important difference when similar sales yield margins that produce a second customer benefit from reducing retail rates for other customers under their purview, (e.g., FPL ratepayers in this example).

Q. ISN'T THIS TYPE OF THINKING JUST SOME SORT OF PAROCHIAL BIAS?

A. I do not think so. Regulation is based on the premise of a just and reasonable return for a prudent investment. If customers in the regulated entities can sometimes effectively share or utilize the same fixed costs (e.g., FPL's generation investment), and both are better off, then regulators should, other things equal, favor such results over merchant plants and out-of-state marketers. The latter generators are not evil. Their generation profits are generally not obscene. However, if regulators seek lower regulated prices, not just economic efficiency, they would and should favor the transactions that are "win/win" for two groups of regulated customers, such as TECO and FPL customers in this discussion.

Q. HOW SIGNIFICANT ARE UTILITY PURCHASES, AND THEREFORE THIS EXTENSION IN YOUR DISCUSSION, IN THE FLORIDA PENINSULA?

A. I show in Exhibit CJC-6 the total electricity requirements and their source, (i.e., self-generation, Florida purchases, out-of-state purchases) for the three investor owned utilities in the Florida Peninsula in 1996 through 1998.

In general, about eighty percent of the IOU requirements are self-generated and twenty percent are purchased. About two-thirds of these IOU purchases come from within the state and about one third is purchased from outside the state.

Q. HOW WOULD THESE PURCHASES AFFECT YOUR CONCLUSIONS CONCERNING THE REASONABLENESS OF DR. NESBITT'S APPROXIMATE $32 PER MWh PRICE?

A. The answer to this question is complicated by how one supposes the prices paid would be treated and would affect the dispatch or market-clearing price. Most purchases have both an energy and demand charge component. The former payment varies with the MWhs sold in any hour of the year. Accordingly, the energy charge is a variable cost that system dispatchers would use in a regulated market to determine when it is cheaper to purchase than to generate electricity.

In a competitive market, if potential sellers were forced to compete by bidding against each other to make a sale, it would also be reasonable to expect each generator to bid each generating unit at its short-run marginal cost, (i.e. its system lambda or variable energy and variable O&M cost). Assuming the purchase price for energy is based on short- run running cost, we could use the energy charges for these utility purchases in our analysis to determine the effect of such purchases on the average annual market clearing prices in either a regulated centrally dispatched world or in a perfectly competitive market in which no generator had market power and all units bid their system lambda, or marginal running cost. The resulting average annual market clearing prices would essentially be the same under both circumstances.

Q. DID YOU PERFORM SUCH AN ANALYSIS?

A. Yes. I began by determining the average energy charges for all the purchases made by the three utilities for the three years in my analysis. While not relevant at this point, I also calculated the average annual prices for demand charges based upon the demand charges and annual energy purchased for the same years and utilities. Both types of prices are shown in Exhibit CJC-7. While not exactly a joint dispatch price because I did not have energy prices for purchases on an hourly basis, I find that the combined average Florida Peninsula energy prices would be slightly less when I add energy purchases at their average prices and amounts to the supply stack (i.e., average hourly system lambda prices) of owned and operated utility plants in the Florida Peninsula.

For example, in 1998, the weighted average of average energy purchases and the average annual hourly system lambda are as follows:

1998 WEIGHTED AVERAGE PRICE OF ENERGY PURCHASES

And the Hourly Prices of the Most Expensive Dispatched Unit

($ Per MWh)

	System Lambda	Weighted Average
FPL	$20.30	$19.73
FPC	$18.30	$19.18
TECO	$13.94	$15.46*
Combined	$21.14	$20.87

*I used scaled values for TECO. These prices adjust 1997 system lambda for changes between 1997 and 1998 in the running costs for Florida electricity generation. Often these TECO prices would be inframarginal and not affect the hour's system lambda and *vice versa*.

I conclude that combining energy purchases and system lambdas would mean that FPL's weighted average price declines; TECO's and FPC's prices increase. This is because FPL is the dominant utility seller to other utility companies in Florida. The overall Florida Peninsula price is essentially unchanged ($21.14 versus $20.87.) This is shown in Exhibit CJC-8.

Q. WHAT DOES THIS REFINEMENT TO YOUR ANALYSIS MEAN?

A. First, I conclude that energy purchases are currently used by Florida utilities, along with self-generation, to minimize retail prices and system costs. There is nothing new in this analysis that would cause me to accept Dr. Nesbitt's projected \$32.00 average price for new generation. Dr. Nesbitt's estimate is not consistent with the current dispatch costs, purchase power and other facts in the Florida Peninsula. By overstating the price of energy significantly, Dr. Nesbitt has grossly overestimated the benefits he claims for either a new merchant plant, or any combined cycle plant, regardless of ownership, in the Florida Peninsula.

Second, I observe that if the generation currently sold in the Florida Peninsula was bid against the current supply stack owned by these three utilities at system lambdas and average energy prices, the average hourly price result would yield about the same average hourly market clearing price of about \$21 per MWh in 1998, and not the \$32 per MWh that Dr. Nesbitt used in his analysis.

Regardless of regulation, (i.e., the *status quo*), or perfect competition, (i.e., bidding short-run marginal costs), there is no reason to expect prices that would approach the approximate \$32 per MWh that Dr. Nesbitt used to inflate his benefit calculations and falsely conclude that new merchant plants would be virtually paid for in one year and represent "manna from heaven." There are no free lunches! Dr. Nesbitt simply overstates his falsely claimed benefits by using projected market clearing prices of \$32/MWh that exceed by more than fifty percent more realistic market clearing price estimates and current costs in

Florida. I show these results in greater detail in Exhibit CJC-8. In the first panel, I show the system lambda dispatch average prices exclusively. The second panel shows the energy charge for power purchased within Florida. The third panel shows the energy charge for power purchased from outside Florida. The fourth panel shows the effect of adding average (weighted) energy purchases prices from both within and outside of Florida to these system lambda average prices.

Q. DOES THIS COMPLETE YOUR REFINEMENTS TO DETERMINE THE REASONABLENESS OF DR. NESBITT'S PROJECTED PRICE OF $32 PER MWh?

A. No. I performed an additional sensitivity test. I added the average annual demand charges per MWh for out-of-state purchases to reflect the fact that, currently, these prices are paid to non-Florida generators for sales made in the Florida Peninsula. I specifically did not add such demand charges for energy supply by Florida generators because, as I explained above, these payments over energy costs would typically be used to reduce other retail rates in Florida. The effect of adding out-of-state demand charges for the combined weighted average prices is as follows: **($ Per MWh)**

	Energy Only	Including Out-of-State Demand Charges
1998	$20.87	$21.91
1997	$23.37	$24.61

1996	$24.00	$25.21

Q. WHAT DOES THIS REFINEMENT DEMONSTRATE?

A. In competitive markets, fixed costs (i.e., demand charges) will mostly not affect marginal bids or market clearing prices. Therefore, in a competitive market, this refinement would not be appropriate unless the market had short-term supply shortages, transmission constraints or some other temporary emergency.

Under regulation, these contract prices would be paid by Florida ratepayers and be recovered by owners (i.e., not used to affect other Florida rates). Therefore, I calculated the effect of these payments. However, when I do so, I still find 1998 weighted average "energy" prices are below $22 per MWh for the Florida Peninsula. This is about $10 per MWh below the price Dr. Nesbitt used to inflate his claimed benefits and other exaggerations.

Q. WHAT PERCENT OF WITHIN FLORIDA SALES DO NOT RESULT IN LOWER RETAIL PRICES FOR THE SELLERS' RETAIL CUSTOMERS?

A. Sales made by qualifying facilities in Florida and by within state merchants comprise about seventy percent of the within state purchases of the three investor owned utilities. These sales are also about ten percent of the annual electricity requirements for these IOUs. I have included the demand charges for these sales along with the demand charges for out-of-state to determine a final estimate of system-wide energy prices for 1998, as follows:

1998 WEIGHTED AVERAGE PRICE OF ENERGY

PURCHASES WITH OUT-OF-STATE AND NON-UTILITY WITHIN STATE DEMAND CHARGES AND THE MOST EXPENSIVE DISPATCHED UNIT

($ Per MWh)

	Include Only System Lambda & Energy Charges	Add Out-of-State Demand Charges	Add Non-Utility Demand Charges
FPL	$19.73	$20.88	$23.99
FPC	$19.18	$20.44	$25.65
TECO	$15.46	$15.55	$16.51
Combined	$20.87	$21.91	$25.28

This table shows that the Florida Peninsula utility supply mix is essentially in long-run equilibrium with a combined running rate of about $25 per MWh. This is consistent with new combined cycle natural gas-fired power stations at about $25 per MWh (all-in annual average costs), on a national basis, and about $2 to $3/MWh higher in Florida most likely due to higher natural gas transportation costs and weather. Thus, there is no reason to believe Dr. Nesbitt's assertion that a $32 per MWh price should be used to calculate benefits, to plan system expansion, or to formulate regulatory policy.

Q. IS IT YOUR CONCLUSION THAT A $32 PER MWh AVERAGE ANNUAL MARKET CLEARING PRICE IS IMPOSSIBLE IN THE FLORIDA PENINSULA?

A. I would not say with absolute certainty that a $32 per MWh price is impossible. What I will say, however, is that under current and likely fuel costs, some form of economic dispatch under regulation, likely technology and/or highly competitive power markets in the future, that a $32 per MWh price is unreasonable and highly unlikely. Furthermore, under the above conditions, for such a price to occur it would most likely be due to an extreme emergency, unfair and inefficient competition, and most likely could not be sustained for very long.

Q. HOW WOULD AN EMERGENCY POSSIBLY CAUSE SUCH A HIGH "MARKET" OR REGULATED PRICE IN FLORIDA?

A. Electricity is about supply and demand, and/or matching loads and dispatch in least cost or merit order. Excess unanticipated demand matched with unplanned outages and transmission interruptions or constraints could cause very high prices until either a reasonable degree of normalcy was restored to the market and/or new investments were made.

Q. DOESN'T EVEN THE VERY SLIM POSSIBILITY OF SUCH ADVERSE OUTCOMES MAKE THE CASE FOR NEW MERCHANT PLANTS THAT PROPOSE TO ENTER FLORIDA AND PERHAPS ASSUME ALL INVESTMENT COST RECOVERY RISK?

A. No. Absolutely not! First, Dr. Nesbitt is claiming falsely that the benefits from a new merchant plant are based on roughly a $32 per MWh price year in and year out, not some sort of emergency condition of excess demand or grossly inadequate supply. My first rule of public policy analysis is "to stick to reasonable facts, assumptions and logic; and, do not overstate the case." Dr. Nesbitt has not followed this rule.

Second, I find few facts and no evidence suggesting that Florida faces the prospect of any such chronic reliability emergency. Instead, I find IOUs willing and able to build new generating stations, sign new long-term contracts and promote demand side management and conservation. They are not alone in this effort in Florida.

Third, if OGC is being built to collect above normal market and/or long-term least cost planning prices (i.e., \$32 per MWh versus about \$25 to \$28 per MWh,) this fact needs to be understood. If it is understood, this Commission should recognize that there are much less costly pro-retail consumer options available. These include: (1) building new combined-cycle natural gas-fired generating plants under rate base regulation; (2) extending the life of existing regulated, perhaps nearly fully depreciated, power stations; (3) adding new advantageous purchase power contracts to the mix; (4) expanding demand side management and conservation; and, (5) supporting and encouraging customer supplied options, distributed energy and/or renewables. There may even be additional options.

The bottom line is that Florida would not be well served by a new merchant plant that positioned itself in a non-competitive market in order to cream skim economic rents that are caused by emergency conditions and that result in extraordinary and exceptional reliability payments. Florida regulators should, in my opinion, reject any such proposal or plan. Instead, Florida should continue to favor least cost solutions to both normal and emergency outcomes. Merchant plants should not be allowed to take unfair advantage and be subsidized through excessive payments. Competitive markets would not do so. Neither should Florida regulation.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW AN EMERGENCY SITUATION COULD LEAD TO EXTRAORDINARY AND EXCEPTIONAL RELIABILITY PAYMENTS?

A. Certainly. Assume that OGC is built but does not execute any long-term contracts for its power. In such a situation, it would generally be selling into the Florida wholesale market and receiving ordinary profits for any sales that it makes. Now assume that an unplanned outage caused by an accident or natural disaster causes a severe shortage of power. While demand remains relatively constant, in any such emergency situation, prices could skyrocket, much as they did when prices hit $7000 per MWh in the Midwest last summer. In such a situation, OGC would be able to profit enormously by selling its power for these extraordinary and exceptional market clearing reliability payments. The IOUs in Florida and their customers would have two options under such a scenario: (1) pay the inflated prices demanded by OGC or (2) suffer outages and blackouts.

A second such scenario could play out where an unplanned outage caused by an accident or natural disaster strikes a neighboring state. Again, demand could outstrip supply, causing prices to soar. Given a high enough price, OGC could find it profitable to abandon Florida markets and chase price spikes in neighboring states. This sudden departure for more profitable venues could cause demand to outstrip supply in Florida, causing prices to spike here as well.

It is important to remember that if a plant like OGC proposes was instead built by the incumbent IOUs, these severe price risks to Florida customers would not exist because incumbent IOUs would build these plants under long-term contracts or rate base regulation. Florida regulators should take care not to create an opportunity for merchant plant owners to earn excessive profits and thereby put Florida customers at risk.

Q. WOULD OGC PROVIDE GREATER PRICE SPIKE PROTECTION TO FLORIDA CONSUMERS THAN WOULD A SIMILAR PLANT OR PURCHASE POWER CONTRACT ENTERED INTO BY A REGULATED UTILITY?

A. No. Merchant plants selling into a spot energy market would ride the price spike curve to increase profits. They would also attempt to chase out of Florida price spikes elsewhere in the nation.

Regardless, merchant plants would use either spikes as an opportunity to increase profits. Regulated utilities could not and would not do this with rate base plants. This difference is important for Florida regulation and consumers.

Q. DO YOU AGREE WITH DR. NESBITT'S CHARACTIZATION THAT THE FRCC REPORT "SHOULD BE VIEWED AS INSUFFICIENT IN TERMS OF THE AMOUNT OF CAPACITY ADDITION IT ADVOCATES"?

A. No. I find that the FRCC approach is a reasonable one for Florida. I also note that the FPSC recently approved a stipulation entered into by FPC, FPL and TECO, to increase their respective reserve margins from 15 percent to 20 percent by summer of 2004.[4] These three utilities make up 85 percent of the load in Florida. This commitment should provide the Commission with additional security that OGC is not required for reliability purposes.

Q. WHAT WOULD CAUSE AN IOU NOT TO BUILD A NEW UNIT WHEN A MERCHANT PLANT OWNER WOULD PROPOSE TO BUILD A NEW UNIT?

A. Dr. Nesbitt would build every plant that could make money (i.e. earn a positive NPV) by beating the marginal market clearing centrally dispatched running cost. From an investor's perspective, this is reasonable.

From a least cost regulatory perspective, this is not reasonable. Regulated utilities are forced to equate least cost and least price. Earnings are capped by regulation. Cost efficiency is encouraged and mostly always achieved.

If a regulated utility can extend existing plant life for less costs and lower retail prices than those associated with building a new unit, the IOU usually has a

[4] In re: Generic Investigation Into the Aggregate Electric Utility Reserve Margins Planned For Peninsular Florida, Docket No. 981890-EU, Order No. PSC-99-2507-D-EU, December 22, 1999.

statutory obligation to do so. Incumbents own some nearly fully depreciated generators with high running costs and no significant fixed costs. Replacing these plants to save operating costs would increase fixed costs. Accordingly, regulators and utilities balance these two costs and seek least cost solutions for consumers in Florida. Merchants would not address this balance. Instead, merchants would build when they can take the margin and be content to leave prices high. Utilities are often forced to eschew higher income or profits to keep regulated prices in check. Therefore, IOUs should extend a generator's operating life when overall tariffs are suppressed by retaining older plants that have little or no fixed costs and fuel savings from a new unit do not recover their fixed costs.

These differences between utility owned and operated plants and investments and merchant plants are significant. Regulators seek the scale and scope cost reducing benefits of a regulated monopoly, attempt to set authorized returns at competitive levels for comparable risk, and require utilities to utilize long-term least cost planning. When there are differences, regulated ratepayers receive the benefit. Regulators equate least cost and least price.

Merchant plants propose to alter this convention and establish a unique profit maximizing foothold by extracting the difference between price and cost. The problems represented by this strategy are two-fold. First, under current conditions, consumers would pay more and merchant owners would earn more than consumers would pay and IOUs would earn under cost-of-service, least cost regulation. Second, without full competition, there are virtually no competitive checks on merchant plant profits or incentives to supply and/or any attempt to game the Florida market. These would raise prices for consumers in Florida.

Q. DO YOU AGREE WITH THE SUGGESTION THAT MERCHANT PLANT APPLICANTS WANT MORE COMPETITION?

A. No. I find that businesses that sing of competition's glory are usually seeking a special governmentally sanctioned advantage. I see much of this line of logic in the OGC petition and throughout Dr. Nesbitt's discourse.

Q. WHY IS THIS SO?

A. Competition makes suppliers face all sorts of business risks and economic challenges. If there is an easier and less risky path, businesses will almost always take it. Regulation in Florida has not failed. Other states that are moving quickly to restructure have had significant regulatory problems. Merchant plant investments around the nation are mostly entering high cost and high priced states. Elsewhere, merchant plants are proceeding by telling regulators that they are free, provide enormous benefits and that they will encourage competition.

These plants are not free. They will benefit owners, not retail consumers. Once the merchant plants are established, I do not expect newly built merchant plant owners to seek regulatory changes that would expand competition, and thereby reduce their profits by altering the *status quo*.

Q. DO YOU AGREE WITH DR. NESBITT'S CONCLUSION THAT, GIVEN GEORGIA'S COAL FIRED GENERATION BASE, GEORGIA WILL KEEP ITS COMPETITIVE ADVANTAGE OVER FLORIDA?

A. This depends upon natural gas transportation into Florida and the Clean Air Act compliance costs in Georgia. Dr. Nesbitt tells only part of the story.

Q. DO YOU AGREE WITH DR. NESBITT'S DISCUSSION OF THE A-J EFFECT?

A. No. I know of no U.S. utility, certainly not Dr. Nesbitt's recent Florida clients Duke and PG&E, that padded their rate base to increase their net income and/or shareholder value.

As I explained above, the A-J effect is only conceptually valid if regulated companies can expect to earn higher returns than their marginal cost of capital. Dr. Nesbitt is obfuscating facts, ignoring economic theory, and incorrectly and unreasonably criticizing both regulators and all IOUs, including his own clients.

Q. DO YOU AGREE WITH DR. NESBITT THAT INCUMBENT UTILITIES WILL BUILD PLANTS AND CHARGE PRICES THAT WILL ALWAYS HAVE HIGHER COSTS AND PRICES THAN MERCHANT PLANTS?

A. Of course not! I explain just the opposite would happen in Florida under current conditions.

Q. DOES THIS MEAN THAT FLORIDA NEEDS TO DROP REGULATION AND JUMP TO COMPETITION QUICKLY?

A. No. First, this petition should be analyzed under current rules and this means that the application should be rejected.

Second, I agree with many of the regional and national things that Dr. Nesbitt has said. However, it is not clear to me what Florida gains over the *status quo* by moving to form a statewide competitive market.

I am not making a specific proposal. My purpose is to clarify that the restructuring issue is much more complicated than Dr. Nesbitt implies.

Q. DO YOU AGREE WITH DR. NESBITT THAT OGC'S COST OF CAPITAL IS A NON-ISSUE HERE?

A. No. OGC most likely seeks a higher return and less risk than a regulated firm. Therefore, OGC's cost of capital is <u>the</u> issue here!

Q. DO YOU AGREE WITH DR. NESBITT'S DISCUSSION OF TRANSMISSION?

A. He states some sensible things about "congestion" and transmission capacity. He fails, however, to discuss the FERC's work to expand open access, encourage wholesale markets for electricity, and encourage forming RTOs. I find this strange because he uses a free-wheeling, pro-competitive philosophy to promote merchant plants in Florida. However, he mostly ignores the current regulatory circumstances that undermine the inflated and false benefit claims stated in the OGC Petition.

Dr. Nesbitt also uses current circumstances in Florida, and the southeast generally, that work in favor of a go-slow approach to electric restructuring. More important, he conveniently uses the current state of restructuring to suggest to Florida regulators that there is no need to worry that the merchant plant owners might use Florida's scarce resources to build a plant in Florida only to seek profits outside the state.

I generally think that parochial thinking, while sometimes useful, can be overused. Nevertheless, to reject it entirely, as Dr. Nesbitt suggests, should not be done for the reasons he offers.

Q DO YOU AGREE WITH DR. NESBITT'S ASSERTION THAT OGC IS "TOO FAR SOUTH" FOR OUT OF STATE SALES TO BE AN ISSUE?

A. No. It is virtually impossible to trace MWhs from origin (generators) to destination (load). Electricity flows are governed by the laws of physics. I find Dr. Nesbitt's geographic market statements to be misleading. He fails to address the one issue that Florida regulators concerned with Florida's indigenous electric need should consider.

Let me explain. The OGC will take resources such as land, water, air and natural gas from Florida. The OGC would not be constrained in two important respects. First, OGC owners have the right to make long-term bilateral sales (i.e., enter into contracts) to sell OGC's output to buyers outside Florida. In an open access transmission world, I am aware of no constraints that could be imposed on OGC to prevent such long term contractual sales outside Florida once OGC is operational. Open access transmission could also eliminate regional pancaking and enhance the possibility of such non-Florida sales contracts.

Second, OGC would not have any constraint that would require it to bid its output into the Florida dispatch stack. Dr. Nesbitt correctly points out that OGC can only make money by selling MWhs. However, OGC would be granted a unique opportunity and right to decide to sell or not to sell in Florida or elsewhere. Withholding output to cause a higher market clearing price is what a profit maximizing firm would do if it has market power. Under current rules, OGC would have potential market power.

Third, it is not clear what transmission pricing will be like in the future. With FERC Order 888, it is possible that there will be no pancaked rates to serve as an impediment to OGC selling its power outside Florida. Until transmission issues are sorted out in the future, it is premature for Dr. Nesbitt to insist that OGC is located too far south for it to make out of state sales.

Fourth, given a high enough price, transmission costs, even if subjected to pancaked rates, will not be a factor in limiting sales made out of state. Surely Dr. Nesbitt would not disagree that a merchant plant owner located in Florida would jump at the prospects of chasing prices and selling into a market outside Florida if the market clearing price reached the $7,000 per MWh prices as reportedly seen in the Midwest last summer. Given prices high enough, transmission costs become virtually irrelevant.

Q. HOW WOULD OGC HAVE MARKET POWER?

A. All other utility owned generators must dispatch when called upon by the central dispatcher. OGC would have a unique ability to decide on its own to bid into the market, or not.

Much of the time, OGC's marginal running cost would beat the centrally dispatched system lambda, or marginal cost. However, a merchant plant or group of merchant plants could withhold supply to push the market clearing price higher. A merchant could seek higher margins by selling less. If more than one merchant plant is involved, there could be a form of conscious parallelism or market gaming behavior to keep prices high. Collective merchant benefits do not necessarily require collusion or price fixing.

Incumbent utility generators make no money or margins related to unit dispatch. Accordingly, incumbent utility dispatch follows least cost, location adjusted engineering/economic protocols. However, merchant plants are paid prices equal to the highest marginal cost plants dispatched at any point in time and earn the difference between market prices and the merchant plant's running cost.

Without a fully developed competitive wholesale market in which all generators would compete, the OGC owners would have market power because they will have potential opportunities where they could affect the selection of the last unit in the market. Therefore, they could reasonably affect the price paid to OGC, and game the system in their favor.

This unique opportunity, or quasi-unique if there are a smaller number of similar merchant generators, would be the regulatory equivalent of giving poachers the ability to hunt before the official hunting season began.

I do not dislike merchant plants. However, it is important to establish similar rules, requirements and price terms. If this is not done, monopoly power and unfair economic rents and returns will be created for merchant plants at the expense of consumers and incumbents.

This would hurt incumbents, cheat consumers of benefits, and make merchant plants richer than their inherent risks would justify.

Q. ARE THERE SIGNIFICANT MERCHANT PLANT OWNER RISKS?

A. Not under Dr. Nesbitt's assumed $32 MWh market clearing price. Merchant plants built in Florida under the current regulatory scheme are a license for the owners to print money with virtually no risk to the owners. First, the merchant plant owners can build units with running costs below $20 per MWh in a state with a system lambda, or market clearing running costs, according to Dr. Nesbitt and the applicants of about $32 per MWh, which is well above the merchant plant's cost.

Second, there is no unregulated competitive wholesale market in Florida. And, more than 95 percent of the state's generation comes from regulated utilities, including coops and munis. These utilities are paid on the basis of the specific costs of each unit owned and operated, not the highest cost unit dispatched. This unreasonably gives merchant plant owners super normal profits with virtually no uncertainty or risk.

Third, severe price spikes due to weather, emergencies, outages, etc. will add to merchant plant profits. Similar conditions do not add to incumbents' profits and consumers are effectively insulated from price spikes. In fact, incumbent utilities might even experience losses of income in such circumstances.

Fourth, the present unique status of merchant plants in Florida gives the merchant plant owners monopoly power in the form of withholding supply, which could be used to increase their normal, virtually riskless profits.

Q. WHAT ABOUT CONSUMERS IN FLORIDA?

A. If merchant plants owners are paid the same price as the marginal units displaced, Florida consumers will not experience lower prices for energy, either overall or from electricity directly supplied by the merchant plants. If merchant plant owners earn rates of return on their sales (i.e., as they monetize their margins) that exceed regulated returns, consumers would, in fact, pay more for their energy assuming that IOUs would build plants of a similar design or, if cheaper, continue using existing units with little or no fixed costs.

If merchant plant owners recover their investments in a time pattern or over a time horizon that is different (i.e., faster) than the regulated utilities that would otherwise sell the energy, consumers would also need to pay more in Florida than if an IOU builds a similar unit.

Q. HOW LIKELY ARE THESE REGULATORY FIXED COST RECOVERY DIFFERENCES COMPARED TO MERCHANT PLANTS?

A. Consider two cases. First, new generation built under regulation would have two characteristics. Dr. Nesbitt misrepresents these facts. The IOUs in Florida would build the same type of generation in a similar location and use similar fuel (e.g., natural gas).

IOUs build to meet load growth and reduce the NPV of the costs of operating their system. If both an IOU and a merchant were to build a new 550 MW unit, I would not expect much difference in fixed and operating costs.

The merchant plant owner, however, might withhold output to get a higher price. The merchant plant owner might also shop electricity outside the Florida market. The merchant plant owner will most definitely seek a higher rate of return and shorter fixed cost recovery period. However, the air quality and operating efficiencies would not materially differ between an IOU owned or merchant plant.

In the case where load was supplied by a new combined cycle unit owned by an IOU, consumers would pay less if, as I conclude, fixed cost recovery was less under cost-of-service regulation than under the conditions contemplated in the OGC petition.

Now consider a second case. If the IOU does not add new capacity and satisfies load requirements by generating electricity from a fully depreciated (i.e., no fixed cost recovery) existing unit, this unit is the marginal, price setting unit. Consumers would pay the same to operate this unit as they pay the merchant plant owners. There is no price saving advantage for the merchant plant, and no fixed cost return "on" or "of" burden placed on retail consumers, or in regulated tariffs.

If the incumbent utility owned unit is not marginal, but still fully depreciated, the retail consumers would pay less for utility supplied electricity than merchant units paid the higher market clearing prices. Similarly, comparisons can be made for long-term purchase power contracts that are priced below the market clearing price and not placed into rate base.

Merchant plants are simply not unambiguously the winners Dr. Nesbitt portrays them to be. Purchase power and existing plants usually or probably are better for consumers in Florida than merchant plants priced to market under current conditions. New cost-of-service financed plants with similar characteristics will always be better for consumers in Florida under current situations.

SECTION IV: OTHER SPECIFIC CONCERNS AND AREAS OF INCONSISTENCY BETWEEN THE OGC PETITION AND DR. NESBITT IN CONDUCTING HIS ANALYSIS, DID DR. NESBITT RELY UPON INFORMATION OR MATERIALS SET FORTH IN THE OGC PETITION?

A. The petition to build, own, and operate (BOO) the OGC includes the following that was relied upon or used by Dr. Nesbitt:

(1) OGC's load, operating characteristics and interconnections.

(2) OGC's size, fuel, costs, and in-service date.

(3) The "need" for OGC.

(4) An analysis of the alternatives that were evaluated in terms of economics, reliability, flexibility, usefulness, and strategic value.

(5) Adverse consequences if OGC does not commence service by April 2003.

Q. WHAT IS YOUR CONCERN AND/OR OPINION REGARDING OGC'S OUTPUT AND AVAILABILITY FACTOR CLAIMS?

A. I find these projections to be on the high side. However, my primary concern is that the OGC output estimates fail to consider the fact that OGC will, in the future, cease to be the least-cost plant in the market. As other generating stations enter with lower costs and more efficiency, OGC's output will be displaced and the unit will be retired.

OGC's benefits are overstated by focusing too much attention on "now" and not nearly enough on OGC's likely life-cycle costs and relative to the future market performance.

Q. WHY THEN ARE YOU CONCERNED WITH THE TEN-YEAR FOCUS OF OGC'S OPERATIONS?

A. I am concerned that OGC's owners have a short payback or cost recovery period in mind, which is why their application and Dr. Nesbitt's analyses use ten years. A shorter payback would *increase* OGC's need for higher prices and this would mean higher, not lower, retail prices in Florida.

Q. WHAT CONCERNS DO YOU HAVE ABOUT NATURAL GAS TRANSPORTATION AND SUPPLY?

A. My concerns are mostly related to the details as to how OGC's sponsors propose to hedge price, quantity, and transportation risks. Natural gas markets (commodity and delivery) are highly evolved markets. What petitioners say is not foolish. However, the devil could be in the details. There is simply too much at stake related to natural gas delivery into Florida to let matters stay vague and, perhaps, just too easy. I need more facts. And, I think Florida regulators deserve more facts before they can be expected to make such an important decision.

The information that is shared is relatively skimpy. This is because OGC and Gulfstream plan to take advantage of a relatively new FERC regulatory option in which the shipper and pipeline agree to confidentially negotiated transportation tariffs, terms and conditions. However, it is one thing to allow negotiated rates where a plant has alternate natural gas supply sources. It is quite another where the negotiated rates represent the plant's sole source of natural gas. This situation is exacerbated in that the natural gas pipeline with which OGC has signed its agreement has yet to be approved or built. In such situations, confidentiality could lead to price discrimination at the expense of shippers and their ultimate retail electric customers.

While I do not necessarily need to know the details of the transportation agreement and FPC does not necessarily need to know the details, this Commission does need to assure itself that natural gas supplies would continue to flow to Florida at reasonable prices during various natural energy market conditions that could arise in the future. Regulators need assurances that natural gas prices will not fly up, and that consumer protection and hedges are in the contract. There remain unanswered questions regarding natural gas prices, natural gas suppliers and natural gas transportation costs. Regulators should get these answers to the questions to assure themselves that Florida's retail customers will be protected.

OGC and Dr. Nesbitt claim that competitive merchant plants will supply electricity to the Florida Peninsula most of the time. Regardless, there are also suggestions that competitive merchants might "chase electricity price" spikes and that merchant plants would help the gas industry to "monetize" the basis differential between Florida and Henry Hub, or wherever the gas supply originates.

Such competitive responses to shortages elsewhere may improve U.S. national economic efficiency, while <u>simultaneously</u> increasing energy prices in Florida. Accordingly, Florida consumers must rely on this Commission to ask the right questions and uncover the necessary information to protect them from excess risk and high prices. In this circumstance, the regulatory need for information is in direct conflict with OGC's pipeline suppliers' need for pricing confidentiality.

Q. DO YOU HAVE OTHER CONCERNS?

A. Yes. The natural gas pipeline industry is not particularly competitive in this region. Furthermore, the FERC restricts incumbent pipelines from offering market-based transportation services. These combine to raise questions in my mind concerning the degree of competition in the natural gas transportation industry into Florida. Accordingly, confidentiality seems like an opportunity to price discriminate and potentially to force unreasonable risks on shippers and downstream customers, which would include regulated retail electric consumers in Florida.

Q. WHY DOES 24 HOURS OF BACK-UP FUEL OIL STORAGE RAISE POTENTIAL CONCERNS?

A. Generally, I would prefer a bigger fuel oil back up buffer than 24 hours, plus assumed truck delivery. I recognize that, for a single merchant plant, the economic cost of such storage could be too expensive. This would probably lead me to favor incumbent IOU projects of a similar size and dual-fuel capability that could more effectively and efficiently back up each other by pooling their storage and sharing on-site storage so that units owned by IOUs could lean on each other.

Additionally, I am again concerned that the devil is in the details. The adequacy of Petitioner's back-up plan is contingent on several factors. For example, whether the natural gas outage affecting the pipeline is localized or affects the entire state, whether an adequate supply of fuel oil is available, whether an adequate supply of trucks is available are all questions that will affect adequacy of the Petitioner's back-up plan. Again, these factors all depend on whether a natural gas delivery interruption is localized or statewide, or short or long-lived. I have experience in allocating fuel oil during shortages and know that it is a very difficult task.

Additionally, I have some reservations that the Petitioner's plan to replace the fuel oil, as it is burned, through tanker truck deliveries about every 20 minutes, or 68 deliveries per day if the natural gas interruption lasts more than 24 hours. Whether this plan is reasonable might depend on whether Petitioner planned to have one tanker truck hook-up or two. Again, the Petition does not contain sufficient detail for this Commission to make a reasoned decision that would protect retail consumers. And all these details directly affect Dr. Nesbitt's assumptions and, therefore, his results.

Q. WHAT CONCERNS DO YOU HAVE ABOUT OGC'S PERFORMANCE, AS DESCRIBED IN THE PETITION AND RELIED UPON BY DR. NESBITT?

A. The petition incorrectly conveys the impression that OGC, and only OGC, can achieve the performance parameters, such as heat rates, output, etc. set out in their petition. This theme is carried through in Dr. Nesbitt's testimony. There is no reason that any of Florida's IOUs could not build plants that are substantially identical to the one proposed by OGC. If regulators doubt IOU performance, they could adopt various performance incentives that would virtually assure results and restrict payment for any failures. Furthermore, with time, newer units will undoubtedly surpass the OGC plant in performance.

Q. WHAT ARE YOUR CONCERNS WITH DR. NESBITT'S DISCUSSION OF THE "NEED" FOR OGC?

A. Dr. Nesbitt's discussion of "need" is totally misleading. First, need is "demand relative to supply." OGC gives itself the exclusive supply nod. This is not logical or reasonable. Others, including IOUs, are prepared to meet any supply gap. Second, need also involves dollars. Are consumers willing to pay to reduce any risk of supply shortfalls? Can conservation and/or load control fill any potential gap more efficiently? Will others (*e.g.*, incumbents) step up and fill the potential gap at the same cost to society (investment plus operating costs)? Will others (*e.g.*, incumbents) under rate base regulation fill the gap with lower consumer prices? Can others (*e.g.*, incumbents) be expected to assume more risks and stay in the market as long as regulators think their presence is needed?

I recognize my answer includes questions. I could rephrase my answer to eliminate this approach. However, regulators should not be lulled by the OGC petition and Dr. Nesbitt into thinking that OGC is either the "only" or even the "best" alternative. At most, I find this OGC proposed technology to be simply the best generating option for a merchant plant owner in Florida at this point in time. I certainly do not think there is any evidence that OGC beats other ownership/regulatory approaches, or that infra-marginal merchant plants priced to market are the best approach for Florida.

Q. DO YOU AGREE WITH DR. NESBITT'S CHARACTERIZATION OF THE VIRTUAL EASE AND GUARANTEES RELATED TO RATE BASE REGULATION?

A. No, I do not. Dr. Nesbitt is either unaware of the last two decades of utility industry history, or seeks to misrepresent and overstate their case for a merchant plant petition. As a subsidiary of an IOU, petitioners must know that Dr. Nesbitt's characterization of regulation, as well as their own characterization in the Petition, is just plain disingenuous. Perhaps as a PG&E subsidiary based in Massachusetts, the petitioner is not aware of the cost disallowances and other strong-handed actions of California regulators. Certainly, the petitioner's parent company is well aware that there are no guarantees, and certainly no free lunches, in the regulated world.

Regulators are also much smarter than to be misled by this. Regulators should, and I trust will, compare "merchant" and "rate base" options on an "apples to apples" basis. Level playing fields, performance incentives, and equal opportunity to enter are important. And, when different, as they are here, regulators need to consider "least price," not just "least cost."

Regulators that restructure seek the cost and price benefits of competition and economic efficiency. In states where regulators have not gotten this right under regulation in the past, there has been a move to restructure in hopes of fixing a regulatory problem. In states like Florida, where regulators have historically mostly gotten it right and achieved least cost given the state's resources and location, there is no great political or regulatory rush to dump regulation and try something that is very complex, as evidenced by other states that are still working out transitional and institutional problems.

Q. WHAT IS THE VALUE OF MORE NATURAL GAS TRANSPORTATION INTO FLORIDA?

A. I think it is high. However, I also think that natural gas pipeline companies would consider incumbent IOUs to be just as desirable and worthy customers as merchant plant owners. Therefore, I find no strategic or economic advantage in terms of natural gas delivery for merchant plants over incumbent IOUs. Certainly, I see no evidence that suggests that new natural gas transportation will not be built in Florida unless merchant plants are approved. In fact, there are three natural gas pipelines vying with each other for the right to build a new natural gas pipeline into Florida. The petitioner's presence in the state is clearly not relevant to the other two pipelines. Further, I seriously question any characterization of this plant as an anchor tenant for the pipeline, implying that without this plant, the pipeline might not be built. The pipeline, according to petitioners will have a capacity of 1 billion cubic feet per day. This is more than sufficient to supply ten plants of OGC's particular size.

Q. SHOULD CONSERVATION, OPERATING COST, AND ENVIRONMENTAL BENEFITS MATTER?

A. Yes. Incumbents can be encouraged and required by regulators to promote conservation. Regulators have no such authority over merchant plants. Thus, from a regulatory standpoint, the incumbent IOUs are superior to merchant plants. Ownership structure does not affect operating costs and environmental benefits, especially if operating incentives are added to the cost-of-service rate base options. The least price regulatory objective still matters. Under the current circumstances, these comparisons favor similar plants owned by incumbent IOUs, not merchant plants.

Q. DO YOU AGREE THAT MERCHANT PLANTS REPRESENT "NO RISK"?

A. No, I do not. If energy prices increase with demand or supply side forces, merchant plants will raise their prices (note priced-to-market terms) and profits. Conversely, regulated utilities would charge prices based on original cost less depreciation and not raise prices when and if demand exceeds supply. Higher consumer prices in Florida are a real risk under the merchant plant option. I do not find the merchants offering fixed price sales contracts to regulators that "meet or beat" similar plants that would be built under rate base regulation.

There is also risk of merchant plant market exit, or even sales out of market when they chase higher prices elsewhere. Again, I find no contradictory assurances emanating from the merchant petitioner that would have assured me as a regulator.

Q. DO YOU AGREE THAT MERCHANT PLANTS PROVIDE SUPERIOR AND MORE COST EFFECTIVE RELIABILITY THAN OTHER APPROACHES?

A. Definitely not! Merchant plants do not have "must-run," "must-bid," or "duty to supply" responsibility. They may sell out of market and/or withhold supply in Florida. Both are likely if full wholesale electricity competition does not exist in Florida.

Furthermore, when merchant plants operate to provide reliability during very constrained peak demand conditions, merchant plants would extract very high reliability payments in the form of "price-to-market" terms and conditions. At best, merchants would supply reliability equal to a rate base plant, but at much higher prices for Florida consumers. At worst, reliability would be less than a similar rate base plant and would cost more.

Q. CAN YOU PROVIDE AN EXAMPLE THAT DEMONSTRATES WHY A MERCHANT PLANT CANNOT BE RELIED UPON TO PROVIDE SERVICE THAT IS AS RELIABLE AS THE SERVICE PROVIDED BY UTILITY OWNED GENERATION?

A. Yes. An excellent example is provided by examining Reliant Energy's recent response to the FRCC when the FRCC requested that Reliant Energy bring its three units at Indian River on line commencing at 10:00 P.M. on December 31, 1999 for FRCC's Y2K Plan. The FRCC's Y2K plan is attached as Exhibit CJC-4. Reliant's initial refusal to operate its plant is attached as Exhibit CJC-5. Reliant had earlier purchased the three units from the Orlando Utilities Commission (OUC) under a Power Purchase Agreement. Under the terms of that agreement, OUC could require Reliant Energy to provide power to OUC and OUC would compensate Reliant Energy under the terms of the contract. If OUC did not request power, Reliant Energy could attempt to sell the power into the forward or spot energy market. Alternatively, Reliant Energy could choose not to run the units. In response to the FRCC's emergency request, Reliant Energy initially refused the FRCC's request. This refusal was based on Reliant Energy's assessment that no emergency situation existed. Ultimately, under additional pressure from the FRCC, Reliant did acquiesce to the FRCC's request and ran its plants. However, this real life example demonstrates the fallacy of the Applicant's position that OGC will provide reliability to Florida that would match that provided by utility-owned generation. This Commission simply cannot rely on a merchant plant for reliability purposes when the Commission does not have jurisdiction over the merchant and the merchant can, at its sole discretion, decide whether an emergency situation exists and whether or not it will choose to respond to "emergency" requests and run its generation. A merchant that can, at its sole discretion, decide whether or not it will run its units does not provide reliability in any reasonable sense of the word. And such a plant can demand and extract extraordinary reliability payments and/or other concessions in order to get it to agree to run.

Q. SHOULD OGC'S CAPACITY BE USED IN CALCULATING THE AGGREGATE RESERVE MARGIN FOR PENINSULAR FLORIDA?

A. No. If OGC's capacity is not committed via a long-term firm purchase contract, I do not think that it should be counted towards satisfying the aggregate reserve margin. My reasons for this are identical to the reasons I stated above for why OGC does not provide true reliability for Peninsular Florida. Furthermore, Dr. Nesbitt discusses how merchants would likely chase high peak prices out of market. Once committed, a generator cannot reasonably be expected to supply necessary reliability.

Q. DR. NESBITT ASSERTS THAT A UTILITY'S PURCHASE POWER COSTS ARE OVERSEEN BY THE FPSC. DOES THIS ASSUAGE YOUR CONCERNS?

A. No. In fact, it confirms them. The FPSC currently has and will in the foreseeable future continue to have regulatory oversight over the state's IOUs. If the OGC petition is granted, that would not be true of OGC.

Let's assume price spikes occur, driving the market price to $7,000 per MWh in a single hour, which would increase the average price by about $0.80 per MWh for each hour in the year in which such a price spike occurred. The IOUs would be forced to purchase power from OGC at that high price if it was needed. The FPSC would not be able to control what the merchant plant charged. Nor would the FPSC be able to disallow the power purchase at the inflated rates if the power was needed and it was the most economical power available. This is a vastly different result than if the IOU had built the plant. In such a case, the FPSC could control the price and protect Florida ratepayers. It is disingenuous for the merchant plants to imply that the market will discipline the price. There is no such market yet in existence. The only way for the FPSC actually to insert some meaningful influence into this system is to require the merchant plant to sell to the IOUs at a price capped by the cost of service price of the unit displaced by the merchant plant or the cost of service price of the unit last dispatched by the IOU. Only in this way could the FPSC be reasonably assured that there would be a semblance of economic discipline over prices. Under the regime that exists today, neither the FPSC nor the yet to be formed market can exercise any disciplinary force on the prices that a merchant plant can charge.

Q. ARE THERE TRULY "NO STRINGS ATTACHED" TO THIS MERCHANT PLANT?

A. No. OGC seeks to price-to-market, while supplying an infra-marginal product. As I explained in Section II, this is a real economic advantage to the owner, virtually guaranteed by the current regulatory circumstances in Florida, and thereby guaranteed by IOUs and their customers.

Accepting arguendo that one merchant plant was needed to point to the best technology and fuel type, I still conclude that regulators now need to address least price and best reliability over time. Alternatively, regulators should plan to open up markets to full-scale competition only as part of a comprehensive restructuring effort. The petitioners for OGC want neither. They prefer a quiet, comfortable, riskless position in which they can "cream skim." Regulators should not allow this.

Q. DOES OGC PROVIDE ANY TIMING ADVANTAGE OVER INCUMBENTS?

A. No. Incumbents can and would build new generating stations if regulators support such expansions and agree rate base regulation is in the public interest.

SECTION V: CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. There are four points that I would like to emphasize. First, a merchant plant built in Florida would not satisfy reliability or reserve margin concerns and requirements. A merchant plant is free to sell its output outside Florida. A merchant plant is also free to withhold supply and attempt to manipulate higher prices if it chooses. Further, as this Commission is well aware, constructing any power plant in Florida uses up scarce resources, including air, water, land, and natural gas transportation resources. Consequently, no plant should be approved if it cannot meet the reliability objective/need tests. To allow a plant such as OGC to be built would use up scarce resources and make it more difficult to secure approval to build a plant that would actually address reliability or reserve margin issues at the least price and cost for Florida consumers. Unless this Commission imposes some form of must-run, must bid, price cap restrictions on this proposed merchant plant, it simply cannot be counted upon to meet any reliability needs in Florida, and should not be built.

Second, the proposed merchant plant does not meet an economic need. Dr. Nesbitt makes a fatal error, carried forward in the Petition, in failing to recognize that under cost-of-service regulation, there is no difference between price and cost. However, this dynamic changes and is simply untrue where a merchant plant is dropped into the middle of a cost-of-service regulated market and allowed to cream skim under the guise of pricing to market. In the regulated market, least cost equates to least price. In a perfectly competitive market, competition will introduce much the same pricing discipline. But allowing a merchant plant to price to market in a predominantly cost-of-service regulated market gives that merchant plant market power and leads to imperfect competition. This will benefit only the merchant plant's owners at the expense of consumers in Florida. Dr. Nesbitt's analysis is fraught with so many logical and mathematical errors so as to render it utterly useless to this Commission in establishing that the proposed merchant plant satisfies the economic need *requirement. It should be ignored entirely.* In fact, I have demonstrated that the Petitioner's plan to introduce imperfect competition in Florida will be economically inefficient and cost consumers more than if an incumbent IOU had built the plant. Thus, the Petitioner fails to demonstrate that the proposed merchant plant meets any economic need in Florida, or that it is superior to cost of service regulation.

Third, despite Dr. Nesbitt's attempts to assert otherwise, the proposed merchant plant will not be cost effective. When considered on an apples-to-apples basis, an identical plant constructed by an incumbent IOU would cost consumers significantly less over its lifetime than would the proposed merchant plant. This is due to the higher cost of capital and shorter pay back period required by the merchant plant. Over its expected life, the merchant plant would collect more revenue from consumers than would an identical plant built by an incumbent IOU. Dr. Nesbitt's claims of consumer savings resulting from building this plant are hopelessly inflated and based upon bogus assumptions.

Fourth, in much of my testimony, I explained why incumbent utilities could build the same type of combined cycle natural gas fired plant with concomitant lower costs, lower retail prices and equivalent external benefits. Sometimes building a new plant is not always least cost.. For example, demand side management could be a least cost solution. I know that this Commission is interested in securing the lowest priced, reliable energy for Florida consumers. Even if the IOUs in Florida did not have explicit plans to build new capacity, which they do, the Commission would be faced with choosing a merchant plant or keeping the existing fleet of plants running and increasing conservation. I would like to leave the Commission with the thought that it might be wise to hold off on building if existing generation can be kept running at lower overall cost (i.e., both fixed and variable). This is an especially important consideration if the $32 per MWh price used by Dr. Nesbitt is too high and, therefore, his analysis overstates the value of new generation. It might simply be that running older, almost fully depreciated plants past their expected life would result in a lower regulated price. This is certainly better than relying on false assurances and letting a merchant plant cream skim the market at the expense of Florida consumers.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

Exhibit CJC-1

December 1999

CHARLES J. CICCHETTI

PROFESSIONAL EXPERIENCE

1998-present	Jeffrey J. Miller Professor in Government, Business, and the Economy, University of Southern California;
1996-present	Co-Founder, Pacific Economics Group;
1990-1997	Adjunct Professor of Economics, University of Southern California;
1992-1996	Managing Director, Arthur Andersen Economic Consulting;
1991-1992	Co-Chairman, Putnam, Hayes & Bartlett, Inc.;
1988-1991	Managing Director, Putnam, Hayes & Bartlett, Inc.;
1987-1990	Deputy Director, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University;
1984-1987	Senior Vice President, National Economic Research Associates;
1980-1984	Co-Founder and Partner, Madison Consulting Group;
1979-1986	Professor of Economics and Environmental Studies, University of Wisconsin-Madison;
1977-1979	Chairman, Public Service Commission of Wisconsin, Appointed by Governor Patrick J. Lucey (member until 1980);
1975-1976	Director, Wisconsin Energy Office and Special Energy Counselor for Governor Patrick J. Lucey, State of Wisconsin;
1974-1979	Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972-1974	Visiting Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972	Associate Lecturer, School of Natural Resources of the University of Michigan;
1969-1972	Resources for the Future, Washington, D.C.;
1969	Ph.D., Economics, Rutgers University;
1968-1969	Instructor, Rutgers University;
1965	B.A., Economics, Colorado College;
1961-1964	Attended United States Air Force Academy.

EDITORIAL BOARDS

Journal of Environmental Economics and Management;
Energy Systems and Policy, Former Member;
Land Economics, Former Editor.

ADVISORY BOARDS

Alliance for Energy Security;
Association of Environmental and Resource Economics, Executive Committee, Former Member;
Association of Environmental and Resource Economics, Contributing Members Program Committee;
Center for Public Policy Advisory Committee, Former Member;
Department of Energy, Fuel Oil Marketing Advisory Committee, Former Member;
Graduate School of Public Policy at the University of California, Berkeley;
Institute for the Study of Regulation;
National Association of Regulatory Utility Commissioners, Executive Committee and Chairman of the Ad Hoc Committee on the National Energy Act, Former Member;
Public Interest Economics Center, Board of Directors, Former Member;
Rutgers University, Energy Research Advisory Board;
U.S. Chamber of Commerce Energy and Natural Resources Committee.

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CHARLES J. CICCHETTI

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CHARLES J. CICCHETTI

SELECTED ADMINISTRATIVE LITIGATION TESTIMONY SINCE 1980

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Before the Public Service Commission of Wisconsin, Rebuttal Testimony on behalf of Alliant Energy Corporation, Docket Nos. 9403-YI-100 and 6680-UM-100, 23 September 1999.

Before the Public Service Commission of Wisconsin, Direct Testimony on behalf of Alliant Energy Corporation, Docket Nos. 9403-YI-100 and 6680-UM-100, 1 July 1999.

Before the Public Service Commission of the State of Missouri, Surrebuttal Testimony on behalf of Western Resources, Inc. and Kansas City Power & Light, Case No. EM-97-515, 10 June 1999.

Before the State Corporation Commission of the State of Kansas, Rebuttal Testimony on behalf of Western Resources, Inc., Docket No. 97-WSRE-676-MER, 18 March 1999.

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Before the Federal Energy Regulatory Commission, Direct Testimony on behalf of Washington Gas Light Company, Docket Nos. RP91-82-000, *et.al.*, August 27, 1991.

Before the Department of Interior, Comments on Notice of Proposed Rulemaking for Natural Resource Damage Assessment Regulations, Type B Rule (43 CFR Part 11), July 12, 1991.

Before the Arizona Corporation Commission, Rejoinder Testimony on behalf of Arizona Public Service Company, Docket Nos. U-1345-90-007 and U-1345-89-162, June 18, 1991.

Before the Federal Energy Regulatory Commission, Comments submitted in Response to Notice of Public Conference and Request for Comments on Electricity Issues, Docket No. PL91-1-000, June 10, 1991.

Before the Arizona Corporation Commission, Rebuttal Testimony on behalf of Arizona Public Service Company, Phase II, Docket Nos. U-1345-90-007 and U-1345-89-162, May 3, 1991.

Before the Federal Energy Regulatory Commission, Direct Testimony on behalf of United Gas Pipe Line Company, Docket Nos. RP91-126-000, CP91-1669-000, CP91-1670-000, CP91-1671-000, CP91-1672-000, and CP91-1673-000, April 15, 1991.

Before the Massachusetts Appellate Tax Board, Analysis of the Fair Market Value of Boston Edison's Mystic Generating Station, Prepared for Boston Edison Company, December 10, 1990.

Before the Arizona Corporation Commission, Rebuttal Testimony on behalf of Arizona Public Service Company, Docket No. U-0000-90-088, November 26, 1990.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony and Exhibits on behalf of Central Maine Power, Docket No. 90-076, November 16, 1990.

Before the State Corporation Commission of Virginia, Direct Testimony on behalf of Historic Manassas, Inc., SCC Case No. PUE 890057, VEPCO Application 154, November 2, 1990.

Before the Iowa Utilities Board, Comments Prepared at the Request of Iowa Electric Light and Power Company on Iowa's Proposed Rulemaking Related to Utility Energy Efficiency Programs, Docket No. RMU90-27, October 15, 1990.

Before the Arkansas Public Service Commission, Testimony on behalf of Arkla, Inc., Docket no. 90-036-U, August 31, 1990.

Before the Federal Energy Regulatory Commission, Rebuttal Testimony on behalf of Northeast Utilities Service Company, Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and EL90-9-000, July 20, 1990.

Before the Illinois Commerce Commission, Testimony on behalf of Commonwealth Edison, Docket No. 90-0169, July 17, 1990.

Before the Federal Energy Regulatory Commission, Rebuttal Testimony on behalf of New York State Customer Group (Niagara Mohawk Power Corporation; Rochester Gas & Electric Corporation; New York State Electric & Gas Corporation), Docket Nos. RP88-211-000, RP88-10-000, RP90-27-000, June 1, 1990.

Before the Federal Energy Regulatory Commission, Statement on behalf of Public Service Company of Indiana, Docket Nos. ER89-672-000, February 15, 1990.

Before the Federal Energy Regulatory Commission, Prepared Direct Testimony submitted on behalf of The New York State Customer Group, which includes Niagara Mohawk Power Corporation, Rochester Gas and Electric Corporation and New York State Electric & Gas Corporation, Docket Nos. RP88-211-000, RP88-10-000, RP88-215-000 and RP90-27-000, January 23, 1990.

Before the Arkansas Public Service Commission, Rebuttal Testimony on behalf of Arkansas Power & Light Company, Docket No. 89-128-U, January 12, 1990.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony Sponsored by Texas Eastern Transmission Corporation, Docket Nos. RP88-67-000 and RP88-81-000, January 10, 1990.

Before the U.S. Department of Interior, Comments on the U.S. Department of Interior's Advanced Notice of Proposed Rulemaking re: Natural Resource Damage Assessments (43 CFR Part 11), November 13, 1989.

Before the Senate Committee on Energy and Natural Resources, Prepared Statement related to the Demand-Side Provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) Contained in Subtitle B of Title III of S-324, The National Energy Policy Act of 1989, November 7, 1989.

Before the Federal Energy Regulatory Commission, Comments on the Federal Energy Regulatory Commission's Proposed Policy Statement on Gas Inventory Charges, Docket No. PL89-10999, July 1989.

Before the Public Utilities Commission of Texas, Direct Testimony on behalf of Enron-Dominion Cogen Corporation, Docket No. 8636, June 12, 1989.

Before the Maine Public Utilities Commission, Direct Testimony on behalf of Central Maine Power Company, Docket No. 88-310, March 1, 1989.

Before the Public Utilities Commission of Ohio, Comments Submitted on behalf of Dayton Power and Light Company, In the Matter of the Revision and Promulgation of Rules for Long Term Forecast reports and Integrated Resource Plans of Electric Light Companies, Case no. 88-816-EL-OR, November 21, 1988.

Before the Federal Energy Regulatory Commission, Comments of the Energy and Environmental Policy Center, RE: Regulations Governing Independent Power Producers, Docket No. RM88-4-000, July 18, 1988.

Before the Federal Energy Regulatory Commission, Comments of the Energy and Environmental Policy Center, RE: Regulations Governing Bidding Programs, Docket No. RM88-5-000, July 18, 1988.

Before the Federal Energy Regulatory Commission, Comments of the Energy and Environmental Policy Center, Re: Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Docket No. RM88-66-000, July 18, 1988.

Before the Maine Public Utilities Commission, Testimony on behalf of Central Maine Power Company, Docket No. 88-111, June 22, 1988.

Before the Federal Energy Regulatory Commission, Comments of the Energy and Environmental Policy Center, Re: Brokering of Interstate Natural Gas Pipeline Capacity, Docket No. RM88-13-000, June 17, 1988.

Before the Federal Energy Regulatory Commission, Comments of the Energy and Environmental Policy Center, Re: Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Docket No. RM88-6-000, June 16, 1988.

Before the Federal Energy Regulatory Commission, Rebuttal Testimony on behalf of Public Service Company of New Mexico, April 12, 1988.

Before the Federal Energy Regulatory Commission, Oral Comments, Re: Order No. 500, Docket No. RM87-34-000 *et.al.*, March, 1988.

Before the Federal Energy Regulatory Commission, Statement on behalf of Transwestern Pipeline Company, Docket No. CP88-143-000, March, 1988.

Before the Ontario Energy Board, Testimony on behalf of ICG Utilities (Ontario) LTD, The 1987 Amended Gas Pricing Agreement, E.B.R.O. 411-III *et.al.*, November, 1987.

Before the New Hampshire Public Utility Commission, Technical Statement on behalf of Public Service Company of New Hampshire, Filing of special Contract No. NHPUC-54 Between Nashua Corporation and Public Service Company of New Hampshire, October 30, 1987.

Before the Federal Energy Regulatory Commission, Statement on behalf of Arkla, Inc., included as an exhibit in Arkla, Inc.'s Comments on Notice of Proposed Rulemaking, Docket No. RM87-34-000, October 13, 1987.

Before the Pennsylvania Public Utility Commission, Rebuttal Testimony on behalf of West Penn Power Company, Docket No. R-850220, September 28, 1987.

Before the Public Service Commission of New York, Prepared Rebuttal Testimony on behalf of National Fuel Gas Distribution Company, September 14, 1987.

Before the New Hampshire Public Utilities Commission, Prefiled Direct Testimony on behalf of Public Service Company of New Hampshire, Docket No. DR87-151, August 28, 1987.

Before the Pennsylvania Public Utility Commission, Direct Testimony on behalf of West Penn Power Company, Docket No. R-850220, Reconsideration, July 27, 1987.

Before the Commonwealth of Massachusetts Department of Public Utilities, Statement on behalf of Boston Edison Company, Docket Nos. 86-36, June 12, 1987.

Before the State of Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Docket Nos. 87-0043, 87-0044, 8700096, May 4, 1987.

Before the Federal Energy Regulatory Commission, Comments on behalf of Tennessee Gas Pipeline Company, <u>In the Matter of Iroquois Gas Transmission System</u>, Docket No. CP86-523-001, March 9, 1987.

Before the New Hampshire Public Utility Commission, Direct Testimony on behalf of Public Service Company of New Hampshire, NHPUC Docket No. DR86-122, March 3, 1987.

Before the Federal Energy Regulatory Commission, Comments on behalf of Transwestern Pipeline Company, <u>In the Matter of Notice of Inquiry into alleged anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines</u>, Docket No. RM87-5-000, December 29, 1986.

Before the Maine Public Utilities Commission, Testimony on behalf of Central Maine Power Company, Docket No. 86-215, Re: Proposed Amendments to Chapter 36, December 18, 1986.

Before the Utah Public Service Commission, Surrebuttal Testimony on behalf of NUCOR Steel Corporation, <u>In the Matter of the Investigation of Cost of Service Issues for Utah Power & Light Company</u>, Case No. 85-035-06, December 5, 1986.

Before the Public Service Commission of New York, Prepared Direct Testimony on behalf of National Fuel Gas Distribution Corporation, Case Nos. 38947 and 28954, November 21, 1986.

Before the Federal Energy Regulatory Commission, Prepared Rebuttal Testimony on behalf of Transwestern Pipeline Company, Docket No. RP86-126, November 13, 1986.

Before the Federal Energy Regulatory Commission, Prepared Cross-Answering Testimony on behalf of Members of the New England Customer Group, Docket No. RP86-119, October 28, 1986.

Before the Federal Energy Regulatory Commission, Prepared Testimony on behalf of Members of the New England Customer Group, Docket No. RP86-119, October 14, 1986.

Before the Utah Public Service Commission, Rebuttal Testimony on behalf of NUCOR Steel Corporation, Docket No. 85-035-04, September 30, 1986.

Before the State of New Jersey Department of Energy, Board of Public Utilities, Rebuttal Testimony on behalf of Elizabethtown Gas Company, September, 1986.

Before the State of Illinois Commerce Commission, Testimony on behalf of Commonwealth Edison Company, Docket No. 86-0249, August 25, 1986.

Before the Public Utilities Commission of Ohio, Rebuttal Testimony on behalf of Ohio Power Company, Case No. 85-726-EL-AIR, April, 1986.

Before the State of New Jersey Department on Energy, Board of Public Utilities, Testimony on behalf of Elizabethtown Gas Company, Docket No. 8112-1039, March, 1986.

Before the Maine Public Utilities Commission, Rebuttal Testimony on behalf of Central Maine Power Company, Docket No. 85-132, March, 1986.

Before the Federal Energy Regulatory Commission, Comments on behalf of National Economic Research Associates, Inc., Notice of Inquiry Re: Regulation of Electricity Sales-for-Resale and Transmission Service, 18 C.F.R. Parts 35 and 290, Issued June 28, 1985, Docket No. RM85-17-000 (Phase II), January 23, 1986.

Before the Alaska Public Utilities Commission, Rebuttal Testimony on behalf of Seagull, Enstar Corporation, and Enstar Natural Gas Company, U-84-67, December, 1985.

Before the Virginia State Corporation Commission, Rebuttal Testimony on behalf of Dominion Resources, Inc. and Virginia Electric and Power Company, Case No. PUE 830060, November 26, 1985.

Before the Federal Energy Regulatory Commission, Comments on behalf of National Economic Research Associates, Inc., Notice Requesting Supplemental Comments

Re: Regulation of Natural Gas Pipeline After Partial Wellhead Decontrol, Docket No. RM85-1-000 (Part D), November 18, 1985.

Before the Public Service Commission of Wisconsin, Rebuttal Testimony on behalf of Eastern Wisconsin Utilities, Docket No. 05-EP-4, November, 1985.

Before the Federal Energy Regulatory Commission, Oral Comments on behalf of National Economic Research Associates, Inc., Notice of Inquiry Re: Regulation of Electricity Sales-for-Resale and Transmission Services (Phase I), Docket No. RM85-17-000, August 9, 1985.

Before the Maine Public Utilities Commission, Direct Testimony on behalf of Central Maine Power Company, Docket No. 85-132, August, 1985.

Before the Public Utilities Commission of Ohio, Direct Testimony on behalf of Ohio Power Company, Docket No. 85-726-EL-AIR, July, 1985.

Before the House Subcommittee on Energy Conservation and Power of the Committee on Energy and Commerce, Comments on Hydroelectric Relicensing, June 5, 1985.

Before the Public Service Commission of Wisconsin, Direct Testimony on behalf of Wisconsin Gas Company, Docket Nos. 05-UI-18 and 6650-DR-2, June, 1985.

Before the Ontario Energy Board, Testimony on behalf of Unicorp of Canada Corporation, In the Matter of Union Enterprises Ltd. and Unicorp of Canada Utilities Corporation, E.B.R.L.G. 28, Exhibit 10.4, April, 1985.

Before the Utah Public Utilities Commission, Testimony on behalf of NUCOR Steel, Docket No. 84-035-01 (Rate Spread Phase), January, 1985.

Before the Nuclear Regulatory Commission, Affidavit of Charles J. Cicchetti on behalf of Alabama Power Company, October, 1984.

Before the Federal Energy Regulatory Commission, Prepared Direct Testimony on behalf of Consolidated Gas Supply Corporation, Application of Consolidated Gas Supply Corporation for Rate Relief, Docket No. RP82-115, April, 1984.

Before the Public Utilities Commission of Ohio, Rebuttal Testimony on behalf of East Ohio Gas Company, *et.al.*, In the Matter of the Investigation into Long Term Solutions Concerning Disconnection of Gas and Electric Service During Winter Emergencies, Case No. 83-303-GE-COI, March, 1984.

Before the Federal Energy Regulatory Commission, Testimony on behalf of Florida Power and Light Company, Docket Nos. ER82-793 and EL83-24, February, 1984.

Before the Public Utilities Commission of Ohio, Direct Testimony on behalf of East Ohio Gas Company, *et.al.*, In the Matter of the Investigation into Long Term Solutions Concerning Disconnection of Gas and Electric Service During Winter Emergencies, Case No. 83-303-COI, January, 1984.

Before the Federal Energy Regulatory Commission, Supplemental Direct Testimony on behalf of Consolidated Gas Supply Corporation, Docket No. RP81-80, September, 1983.

Before the Arkansas Public Service Commission, Direct Testimony on behalf of Arkansas Louisiana Gas Company, Docket No. 83-161-U, August, 1983.

Before the New Mexico Public Service Commission, Testimony on behalf of Public Service Company of New Mexico, Case No. 1811, July 17, 1983.

Before the Federal Communications Commission, Rebuttal Case Testimony on behalf of Interstate Mobile Phone Company, in American Mobile Commission of Washington and Oregon, CC Docket No. 83-445, June, 1983.

Before the Public Service Commission of Indiana, Prepared Rebuttal Testimony on behalf of Northern Indiana Public Service Company, Case No. 37023, May, 1983.

Before the Public Service Commission of New York, Testimony on behalf of the Industrial Energy Users Association, in Procedure to Inquire into the Benefits to Ratepayers and Utilities from Implementation of Conservation Programs that will Reduce Electric Use, Case No. 28223, May, 1983.

Before the Public Utilities Commission of Maryland, Testimony on behalf of the Mid-Atlantic Petroleum Distributors Association, the Oil Heat Association of Washington, and Steuart Petroleum Company, Case No. 7649, May, 1983.

Before the Connecticut Department of Public Utility Control, Testimony on behalf of the Independent Petroleum Association, Docket No. 83-01-01, April, 1983.

Before the State Corporation Commission of Virginia, Testimony on behalf of the Mid-Atlantic Petroleum Distributors Association, the Oil Heat Association of Washington, and Steuart Petroleum Company, Case No. PUE 830008, March, 1983.

Before the Federal Energy Regulatory Commission, Rebuttal Testimony on behalf of Arkansas Louisiana Gas Company, Docket Nos. RP82-75-000 *et.al.*, February 1983.

Before the Federal Communications Commission, Rebuttal Case Testimony on behalf of Interstate Mobile Phone Company, in American Mobile Communications of Washington and Oregon, CC Docket No. 83-3, February, 1983.

Before the Department of Health and Social Services, Testimony on behalf of Madison General Hospital, In Application for Certificate of Need for Open Heart Surgery, CON 82-026, November, 1982.

Before the Federal Energy Regulatory Commission, Prepared Testimony on behalf of Consolidated Gas Supply Corporation, in Application of Consolidated Gas Supply Corporation for Rate Relief, Docket No. RP82-115, July, 1982.

Before the Federal Energy Regulatory Commission, Rebuttal Testimony on behalf of Consolidated Gas Supply Corporation, Docket No. RP81-80, April, 1982.

Before the Florida Public Service Commission, Testimony on behalf of Florida Power & Light Company, Docket No. 820097-EU, April, 1982.

Before the Massachusetts Department of Public Utilities, Direct Testimony on behalf of Boston Edison Company, Docket No. 906, January, 1982.

Before the New Mexico Public Service Commission, Testimony on behalf of Public Service Company of New Mexico, In the Matter of New Mexico Public Service Commission Authorization for Southern Union Company to Transfer Certain Property to Western Gas Company, NMPSC Case 1689, January, 1982.

Before the Connecticut Department of Public Utility Control Authority, Testimony on behalf of Southern Connecticut Gas Works, DPUC Investigation Into Utility Financing of Conservation and Efficiency Improvements, Docket No. 810707, August, 1981.

Before the Connecticut Public Utility Control Authority, Prepared Testimony on behalf of Connecticut Natural Gas Corporation, July, 1981.

Before the Philadelphia Gas Commission, Testimony on behalf of Philadelphia Gas Works, in PGW Rate Investigations, July, 1981.

Before the California Public Utility Commission, Prepared Testimony on behalf of Pacific Gas and Electric Company, In Application of Pacific Gas and Electric Company for Rate Relief, Application No. 68153, June, 1981.

Before the Federal Energy Regulatory Commission, Prepared Testimony on behalf of Consolidated Gas Supply Corporation, Docket No. RP81-80, June, 1981.

Before the Tennessee Valley Authority Board, Comments on Tennessee Valley Authority Proposed Determinations on Ratemaking Standards, Contract TV-53565A, October, 1980.

Before the Postal Rate Commission, Testimony on behalf of the National Association of Greeting Card Publishers, Docket No. R80-1, August 13, 1980.

Before the Federal Energy Regulatory Commission, Testimony on behalf of Pennsylvania Power and Light Company, <u>Split-Savings and Emergency Tariffs</u>, August, 1980.

Final Report of Consultants' Activities Submitted to Tennessee Valley Authority Division of Energy Conservation and Rates, in <u>Consideration of Ratemaking Standards Pursuant to the Public Utility Regulatory Policy Act of 1978 (P.L. 95-617) and One Additional Standard</u>, Contract No. TV-53575A, May, 1980.

Before the Utah Public Service Commission, Direct Testimony on behalf of NUCOR Steel, PSCU Case No. 83-035-06, 1980.

~~*Declining Price Cost of Service (Utility Built)*~~

Cost of a Plant:	$190,000,000
Straight Line Depreciation:	$6,333,333
Rate of Return:	10.00%

~~Year~~	~~Revenue Requirement~~	~~Straight Line Depreciation~~	~~Net Book Value~~
1	$25,333,333	$6,333,333	$183,666,667
2	$24,700,000	$6,333,333	$177,333,333
3	$24,066,667	$6,333,333	$171,000,000
4	$23,433,333	$6,333,333	$164,666,667
5	$22,800,000	$6,333,333	$158,333,333
6	$22,166,667	$6,333,333	$152,000,000
7	$21,533,333	$6,333,333	$145,666,667
8	$20,900,000	$6,333,333	$139,333,333
9	$20,266,667	$6,333,333	$133,000,000
10	$19,633,333	$6,333,333	$126,666,667
11	$19,000,000	$6,333,333	$120,333,333
12	$18,366,667	$6,333,333	$114,000,000
13	$17,733,333	$6,333,333	$107,666,667
14	$17,100,000	$6,333,333	$101,333,333
15	$16,466,667	$6,333,333	$95,000,000
16	$15,833,333	$6,333,333	$88,666,667
17	$15,200,000	$6,333,333	$82,333,333
18	$14,566,667	$6,333,333	$76,000,000
19	$13,933,333	$6,333,333	$69,666,667
20	$13,300,000	$6,333,333	$63,333,333
21	$12,666,667	$6,333,333	$57,000,000
22	$12,033,333	$6,333,333	$50,666,667
23	$11,400,000	$6,333,333	$44,333,333
24	$10,766,667	$6,333,333	$38,000,000
25	$10,133,333	$6,333,333	$31,666,667
26	$9,500,000	$6,333,333	$25,333,333
27	$8,866,667	$6,333,333	$19,000,000
28	$8,233,333	$6,333,333	$12,666,667
29	$7,600,000	$6,333,333	$6,333,333
30	$6,966,667	$6,333,333	($0)
	$190,000,000	$190,000,000	
	NPV	*TOTAL*	

~~Declining Price Cost of Service (Utility Built)~~

Cost of a Plant:	$190,000,000
Straight Line Depreciation:	$4,750,000
Rate of Return:	10.00%

~~Year~~	~~Revenue Requirement~~	~~Straight Line Depreciation~~	~~Net Book Value~~
1	$23,750,000	$4,750,000	$185,250,000
2	$23,275,000	$4,750,000	$180,500,000
3	$22,800,000	$4,750,000	$175,750,000
4	$22,325,000	$4,750,000	$171,000,000
5	$21,850,000	$4,750,000	$166,250,000
6	$21,375,000	$4,750,000	$161,500,000
7	$20,900,000	$4,750,000	$156,750,000
8	$20,425,000	$4,750,000	$152,000,000
9	$19,950,000	$4,750,000	$147,250,000
10	$19,475,000	$4,750,000	$142,500,000
11	$19,000,000	$4,750,000	$137,750,000
12	$18,525,000	$4,750,000	$133,000,000
13	$18,050,000	$4,750,000	$128,250,000
14	$17,575,000	$4,750,000	$123,500,000
15	$17,100,000	$4,750,000	$118,750,000
16	$16,625,000	$4,750,000	$114,000,000
17	$16,150,000	$4,750,000	$109,250,000
18	$15,675,000	$4,750,000	$104,500,000
19	$15,200,000	$4,750,000	$99,750,000
20	$14,725,000	$4,750,000	$95,000,000
21	$14,250,000	$4,750,000	$90,250,000
22	$13,775,000	$4,750,000	$85,500,000
23	$13,300,000	$4,750,000	$80,750,000
24	$12,825,000	$4,750,000	$76,000,000
25	$12,350,000	$4,750,000	$71,250,000
26	$11,875,000	$4,750,000	$66,500,000
27	$11,400,000	$4,750,000	$61,750,000
28	$10,925,000	$4,750,000	$57,000,000
29	$10,450,000	$4,750,000	$52,250,000
30	$9,975,000	$4,750,000	$47,500,000
31	$9,500,000	$4,750,000	$42,750,000
32	$9,025,000	$4,750,000	$38,000,000
33	$8,550,000	$4,750,000	$33,250,000
34	$8,075,000	$4,750,000	$28,500,000
35	$7,600,000	$4,750,000	$23,750,000
36	$7,125,000	$4,750,000	$19,000,000
37	$6,650,000	$4,750,000	$14,250,000
38	$6,175,000	$4,750,000	$9,500,000
39	$5,700,000	$4,750,000	$4,750,000
40	$5,225,000	$4,750,000	$0
	$190,000,000	**$190,000,000**	
	NPV	*TOTAL*	

~~Levelized Price Cost of Service (Merchant)~~

Cost of a plant:	$	190,000,000
Levelized Cost of a plant per year:		$25,436,968
Number of Years:		20
Rate of Return:		12.00%
Capital Recovery Factor:		0.13387878

~~Year~~	~~Revenue Requirement~~	~~Sinking Fund Depreciation~~
1	$25,436,968	$2,636,968
2	$25,436,968	$2,953,404
3	$25,436,968	$3,307,813
4	$25,436,968	$3,704,750
5	$25,436,968	$4,149,321
6	$25,436,968	$4,647,239
7	$25,436,968	$5,204,908
8	$25,436,968	$5,829,497
9	$25,436,968	$6,529,036
10	$25,436,968	$7,312,521
11	$25,436,968	$8,190,023
12	$25,436,968	$9,172,826
13	$25,436,968	$10,273,565
14	$25,436,968	$11,506,393
15	$25,436,968	$12,887,160
16	$25,436,968	$14,433,619
17	$25,436,968	$16,165,653
18	$25,436,968	$18,105,532
19	$25,436,968	$20,278,195
20	$25,436,968	$22,711,579
	$190,000,000	**$190,000,000**
	NPV	*TOTAL*

~~Levelized Price Cost of Service (Merchant)~~

Cost of a plant:	$	190,000,000
Levelized Cost of a plant per year:		$28,687,340
Number of Years:		20
Rate of Return:		14.00%
Capital Recovery Factor:		0.150986002

~~Year~~	~~Revenue Requirement~~	~~Sinking Fund Depreciation~~
1	$28,687,340	$2,087,340
2	$28,687,340	$2,379,568
3	$28,687,340	$2,712,707
4	$28,687,340	$3,092,487
5	$28,687,340	$3,525,435
6	$28,687,340	$4,018,995
7	$28,687,340	$4,581,655
8	$28,687,340	$5,223,086
9	$28,687,340	$5,954,319
10	$28,687,340	$6,787,923
11	$28,687,340	$7,738,232
12	$28,687,340	$8,821,585
13	$28,687,340	$10,056,607
14	$28,687,340	$11,464,532
15	$28,687,340	$13,069,566
16	$28,687,340	$14,899,306
17	$28,687,340	$16,985,208
18	$28,687,340	$19,363,138
19	$28,687,340	$22,073,977
20	$28,687,340	$25,164,334
	$190,000,000	**$190,000,000**
	NPV	*TOTAL*

Levelized Price Cost of Service (Merchant)

Cost of a plant:	$	190,000,000
Levelized Cost of a plant per year:		$25,436,968
Number of Years:		20
Rate of Return:		12.00%
Capital Recovery Factor:		0.13387878

Year	Revenue Requirement	Sinking Fund Depreciation
1	$25,436,968	$2,636,968
2	$25,436,968	$2,953,404
3	$25,436,968	$3,307,813
4	$25,436,968	$3,704,750
5	$25,436,968	$4,149,321
6	$25,436,968	$4,647,239
7	$25,436,968	$5,204,908
8	$25,436,968	$5,829,497
9	$25,436,968	$6,529,036
10	$25,436,968	$7,312,521
11	$25,436,968	$8,190,023
12	$25,436,968	$9,172,826
13	$25,436,968	$10,273,565
14	$25,436,968	$11,506,393
15	$25,436,968	$12,887,160
16	$25,436,968	$14,433,619
17	$25,436,968	$16,165,653
18	$25,436,968	$18,105,532
19	$25,436,968	$20,278,195
20	$25,436,968	$22,711,579
21	$25,436,968	$0
22	$25,436,968	$0
23	$25,436,968	$0
24	$25,436,968	$0
25	$25,436,968	$0
26	$25,436,968	$0
27	$25,436,968	$0
28	$25,436,968	$0
29	$25,436,968	$0
30	$25,436,968	$0
31	$25,436,968	$0
32	$25,436,968	$0
33	$25,436,968	$0
34	$25,436,968	$0
35	$25,436,968	$0
36	$25,436,968	$0
37	$25,436,968	$0
38	$25,436,968	$0
39	$25,436,968	$0
40	$25,436,968	$0
Undiscounted:	$1,017,478,728	$190,000,000

~~Levelized Price Cost of Service (Merchant)~~

Cost of a plant:	$	190,000,000
Levelized Cost of a plant per year:		$28,687,340
Number of Years:		20
Rate of Return:		14.00%
Capital Recovery Factor:		0.150986002

~~Year~~	~~Revenue Requirement~~	~~Sinking Fund Depreciation~~
1	$28,687,340	$2,087,340
2	$28,687,340	$2,379,568
3	$28,687,340	$2,712,707
4	$28,687,340	$3,092,487
5	$28,687,340	$3,525,435
6	$28,687,340	$4,018,995
7	$28,687,340	$4,581,655
8	$28,687,340	$5,223,086
9	$28,687,340	$5,954,319
10	$28,687,340	$6,787,923
11	$28,687,340	$7,738,232
12	$28,687,340	$8,821,585
13	$28,687,340	$10,056,607
14	$28,687,340	$11,464,532
15	$28,687,340	$13,069,566
16	$28,687,340	$14,899,306
17	$28,687,340	$16,985,208
18	$28,687,340	$19,363,138
19	$28,687,340	$22,073,977
20	$28,687,340	$25,164,334
21	$28,687,340	$0
22	$28,687,340	$0
23	$28,687,340	$0
24	$28,687,340	$0
25	$28,687,340	$0
26	$28,687,340	$0
27	$28,687,340	$0
28	$28,687,340	$0
29	$28,687,340	$0
30	$28,687,340	$0
31	$28,687,340	$0
32	$28,687,340	$0
33	$28,687,340	$0
34	$28,687,340	$0
35	$28,687,340	$0
36	$28,687,340	$0
37	$28,687,340	$0
38	$28,687,340	$0
39	$28,687,340	$0
40	$28,687,340	$0
Undiscounted:	$1,147,493,612	$190,000,000

Levelized Price Cost of Service (Merchant)

Cost of a plant:	$	190,000,000
Levelized Cost of a plant per year:		$33,626,991
Number of Years:		10
Rate of Return:		12.00%
Capital Recovery Factor:		0.176984164

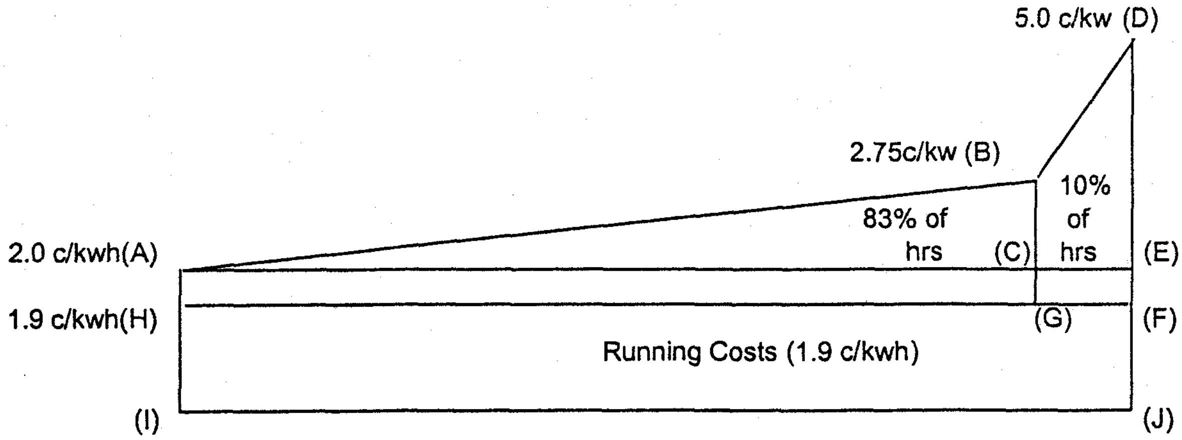
Year	Revenue Requirement	Sinking Fund Depreciation
1	$33,626,991	$10,826,991
2	$33,626,991	$12,126,230
3	$33,626,991	$13,581,378
4	$33,626,991	$15,211,143
5	$33,626,991	$17,036,480
6	$33,626,991	$19,080,858
7	$33,626,991	$21,370,561
8	$33,626,991	$23,935,028
9	$33,626,991	$26,807,231
10	$33,626,991	$30,024,099
	$190,000,000	**$190,000,000**
	NPV	*TOTAL*

Levelized Price Cost of Service (Merchant)

Cost of a plant:	$	190,000,000
Levelized Cost of a plant per year:		$36,425,573
Number of Years:		10
Rate of Return:		14.00%
Capital Recovery Factor:		0.191713541

Year	Revenue Requirement	Sinking Fund Depreciation
1	$36,425,573	$9,825,573
2	$36,425,573	$11,201,153
3	$36,425,573	$12,769,314
4	$36,425,573	$14,557,018
5	$36,425,573	$16,595,001
6	$36,425,573	$18,918,301
7	$36,425,573	$21,566,863
8	$36,425,573	$24,586,224
9	$36,425,573	$28,028,295
10	$36,425,573	$31,952,257
	$190,000,000	**$190,000,000**
	NPV	*TOTAL*

Exhibit CJC-3



Okeechobee Operations				
Profits	MWh (000s)	Avg c/kwh Margin	Millions of Dollars	
Area ABC	3,999	0.38	15.0	$M in profit annually
Area ACGH	3,999	0.10	4.0	$M in profit annually
Area BDEC	482	1.88	9.0	$M in profit annually
Area CEFG	482	0.10	0.5	$M in profit annually
Total	4,481	0.64	28.51	$M in profit per year
Costs	MWh	Avg c/kwh Cost	Total Dollars	
Area HIJF	4,481	1.90	85.13	$M Running Cost

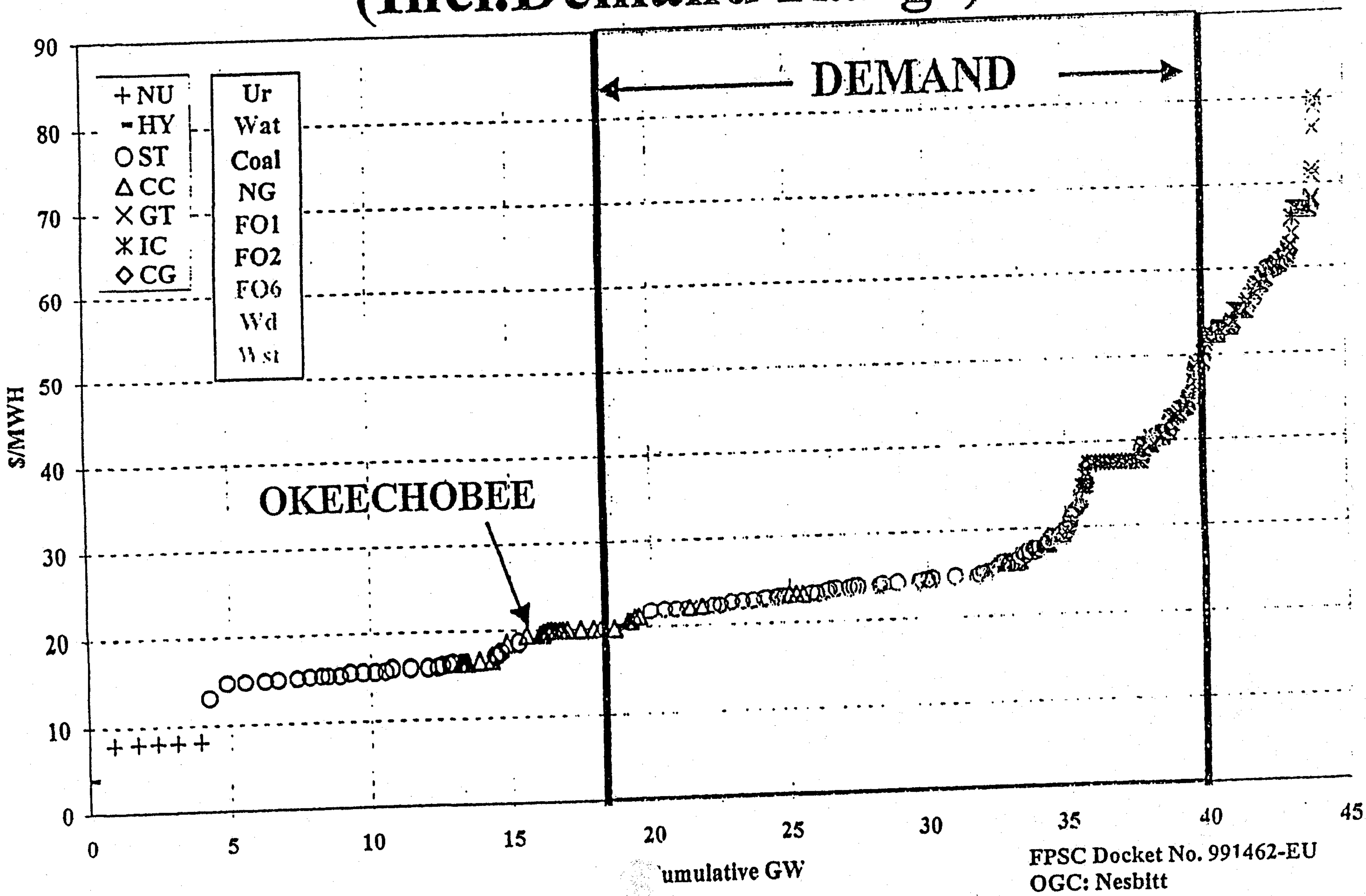
Exhibit CJC-3
ASSUMPTIONS

In developing this exhibit, I utilized several assumptions. First, I used Dr. Nesbitt's Exhibit DMN-5 to determine the prices that what attain in the market at certain hours. In other words, I developed a load curve from Dr. Nesbitt's exhibit. Second, I used Dr. Nesbitt's Exhibit DMN-6 to determine how many hours in each year prices would reach certain levels. In other words, I determined that over the range of hours in which OGC was likely to operate, prices would be between $20 per MWh and $50 per MWh. I further assumed that prices would be between $20 per MWh and $27.50 per MWh 90 percent of the 8,760 hours in a year. I also assumed that prices would be between $27.50 per MWh and $50 per MWh during 10 percent of the 8,760 hours in a year.

Using OGC's running costs of $19 per MWh, I can calculate OGC's margin over the 4,480,740,000 kWhs it is projected to run in these two time periods. During 90 percent of the hours in a year, the average OGC margin is $14.75 per MWh. During the remaining 10 percent of the hours, the average OGC margin is $19.75 per MWh.

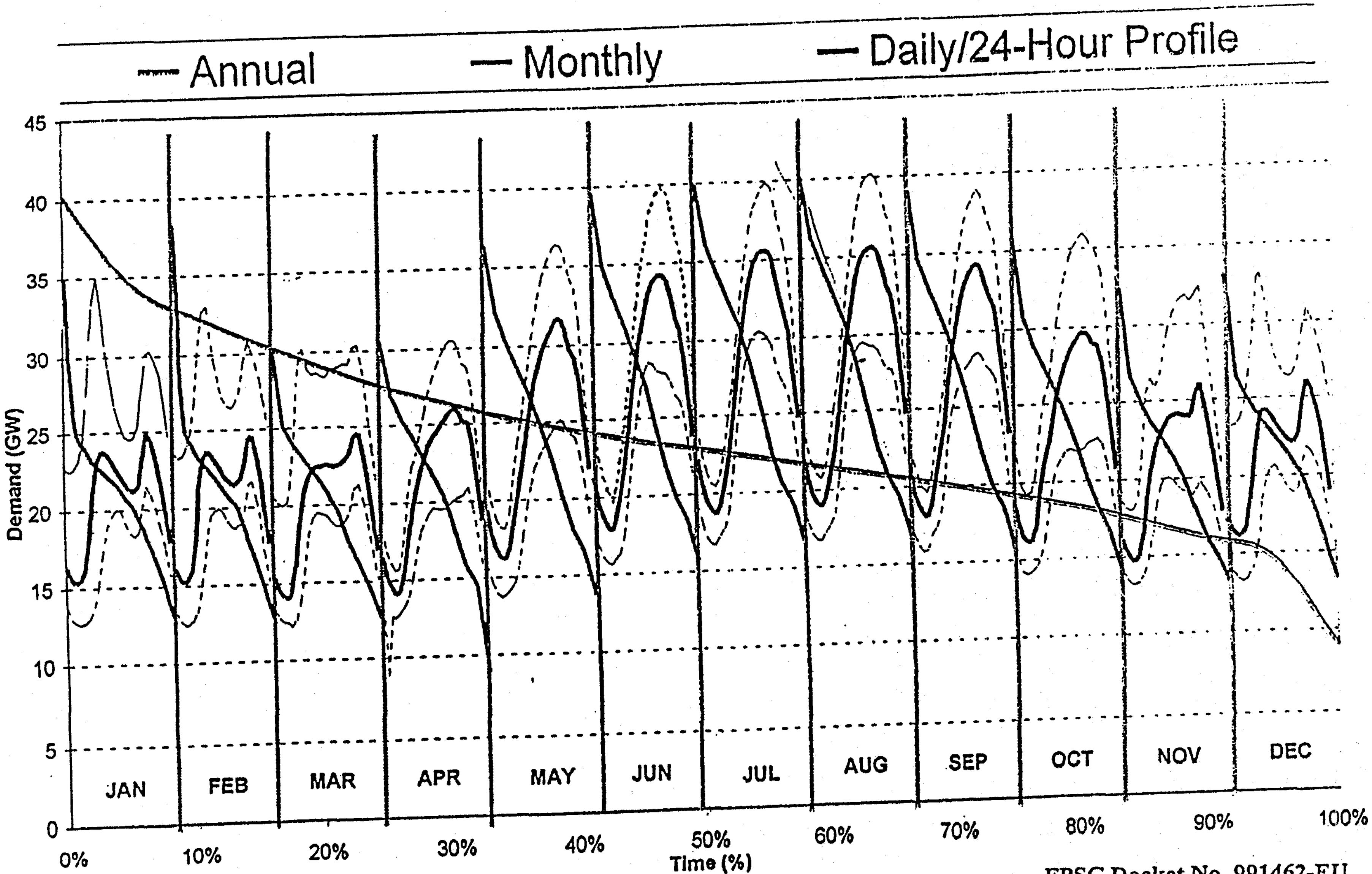
These margins vary linearly in the diagram in this exhibit. I calculate four components that make up OGC's margins. These are represented by the triangle ABC, rectangle ACGH, trapezoid BDEC and rectangle CEFG. Triangle ABC represents the margin generated by the earnings between $20 per MWh and $27.50 per MWh for 83 percent of the hours in the years. Rectangle ACGH represents the margin generated by the difference in OGC's $19 per MWh *running cost* and $20 per MWh, representing the lowest market price during 83 percent of the hours in the year. Trapezoid BDEC represents the margin generated during 10 percent of the hours in the year when the price is between \$27.50 per MWh and \$50 per MWh. Finally, rectangle CEFG is similar to rectangle ACGH, and represents the margin generated by the difference in OGC's \$19 per MWh price and \$20 per MWh during the 10 percent of the year that prices range between \$27.50 per MWh and \$50 per MWh. The total is \$28.51 million in profit annually.

Exhibit 5: FRCC 2003 Supply Stack (Incl.Demand Range)



FPSC Docket No. 991462-EU
OGC: Nesbitt
Exhibit DMN-5

Exhibit 6: FRCC Load Duration Curves



FPSC Docket No. 991462-EU
OGC: Nesbitt
Exhibit DMN-6

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FLORIDA RELIABILITY COORDINATING COUNCIL
405 REO STREET, SUITE 100 • TAMPA, FL. 33609-1094
(813) 289-5644 • FAX (813) 289-5646

FRCC Y2K Contingency Plan

Prepared by:

FRCC Operating Reliability Subcommittee

Prepared for:

FRCC Operating Committee

December 10, 1998
Revised 5/5/99
Revised 11/12/99
Revised 12/1/99

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Contents

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1. Purpose

This document describes the FRCC Y2K Contingency Plan. The purpose of the plan is to mitigate operating risks that could arise due to Y2K computer and other hardware logic errors, and achieve reliable electric operations in the FRCC region during the transition into the Year 2000.

2. Background

Need - Maintaining a reliable supply of electricity during the Y2K transition is of critical importance to the Florida Reliability Coordinating Council (FRCC) and its member utilities. As such, FRCC has developed a plan which identifies the risks, and sets forth strategies which minimize the probability of occurrence and which mitigate the consequences in the event of an occurrence.

Nature of the Y2K Problem in Electricity Production and Delivery - Maintaining a reliable supply of electricity during the Y2K transition is not an insurmountable task. There are four critical areas that pose the greatest direct threat to power production and delivery:

- Power production — Generating units must be able to operate through critical Y2K periods without inadvertently tripping off-line. The threat is most severe in power plants with digital control systems (DCSs). Numerous control and protection systems within these DCS use time-dependent algorithms that may result in unit trips. Most older plants operating with analog controls will be less problematic. Digital controllers built into station equipment, protection relays, and communications also may pose a threat.

- Energy management systems — Control computer systems within the electric control centers across North America use complex algorithms to operate transmission facilities and control generating units. Many of these control center software applications contain built-in time clocks used to run various power system monitoring, dispatch, and control functions. Many energy management systems are dependent on time signal emissions from Global Positioning Satellites, which reference the number of weeks and seconds since 00:00:00 UTC January 6, 1980. In addition to resolving Y2K problems within utility energy management systems, these supporting satellite systems, which are operated by the U.S. government, must be Y2K compliant.

- Telecommunications — Electric supply and delivery systems are highly dependent on microwave, telephone, and VHF radio communications. The dependency of the electric supply on facilities leased from telephone companies and commercial communications network service providers is a crucial factor. With telecommunications systems being the nerve center of the electric networks, it is important to address the dependencies of electric utility systems on the telecommunications industry during critical Y2K transition periods.

- Protection systems — Although many relay protection devices in use today are electromagnetic, newer systems are digital. The greatest threat here is a common mode failure in which all the relays of a certain model fail simultaneously, resulting in a large number of coincident transmission facility outages.

Critical Y2K System Operating Dates

Part of the Y2K risk assessment process is to internally review the risks of Y2K anomalies for various dates. NERC-recommended dates for consideration are listed below in priority order. It is important to recognize that critical transition periods may last only for minutes or hours due to primary causes (i.e. unit trips, loss of primary voice communications, etc.) or for days or weeks for secondary causes such as reduced supplies of natural gas, oil, or coal.

Priority 1 Dates
December 31, 1999 to January 1, 2000 — Rollover to 2000: Date = 010100

Priority 2 Dates
February 28, 2000 to March 1, 2000 — Rollover in/out of leap year date
September 8, 1999 to September 9, 1999 — Special value: Date = 090999

Priority 3 Dates
December 31, 1998 to January 1, 1999 — Special value: Year = 99
August 21, 1999 to August 22, 1999 — GPS satellite clocks expire
April 8, 1999 to April 9, 1999 — Special value: 99th day of 1999

Fortunately from an electric reliability perspective, New Year's Eve falls on Friday December 31, 1999, and January 1 is a Saturday. Because demands on the electric system are reduced from peak conditions at night and on weekends, the electric system conditions are likely to be favorable with light transfers and excess generating capacity available during the most critical Y2K period.

3. Roles and Responsibilities

The success of the FRCC Y2K contingency plan depends on the cooperation, full sharing of information, and diligent effort of the members of FRCC, as well as coordination with NERC and other regional councils. To that end, the roles and responsibilities of participants in the FRCC Y2K program are defined as follows:

FRCC Coordination

- Florida Reliability Coordinating Council (FRCC) — Regional staff will coordinate NERC Y2K activities within the Regions. This includes intra and interregional studies and preparations and assuring participation of all members of the Region.
- Reliability Assessment Group (RAG) - overall responsibility for Y2K plan.
- Operating Committee (OC) - approve operating and contingency plans, and oversee their implementation.
- Operations Reliability Subcommittee (ORS) - develop and implement operating and contingency plans; review individual company plans to ensure compliance with the FRCC Y2K Contingency Plan regarding security of the bulk grid.
- Transmission and Stability Working Groups - perform system studies as requested by ORS.
- FRCC Members - each FRCC members shall:
  - Participate in the FRCC planning and preparations process
  - Ensure that its company has a plan which complies with the FRCC plan
  - Coordinate contingency planning and preparations with its customers

Coordination with External Agencies

In addition to internal cooperation, FRCC Y2K efforts are also closely aligned with those of NERC and the other Regional Reliability Councils. Key partners with the FRCC Y2K Program are identified below.

- NERC - The FRCC program is part of a larger coordinated effort by NERC. NERC staff and support contractors will coordinate the NERC Y2K efforts defined within its plan. This activity includes collecting, consolidating, and distributing information on Y2K problems and solutions, and it includes coordination of contingency planning and preparation at the interconnection and inter-regional level. The information collected will be compiled into a report that will periodically be presented to the NERC Board of Trustees and DOE.
- FPSC - keep state regulatory agencies fully informed as to status of Y2K effort.

- Florida Department of Environmental Protection - secure necessary agreements to ensure flexibility in operating the system during critical periods.

- Florida Division of Emergency Management - coordinate with FPSC and FRCC regarding drills.

4. FRCC Contingency Planning and Preparations Process

The following steps outline the process which FRCC has implemented to develop its contingency plan. This process has been adopted from the NERC recommended process for Y2K contingency planning and preparations.

Step 1: Identify Y2K Operating Risks — Identify sources of risk, both internal and external that may impact the capability to sustain reliable operations into the Year 2000 and beyond. Examples of internal risks include loss or unavailability of generation or loss of functionality within an energy management system. Examples of external risks include loss of leased communications facilities or reduced fuel supplies. For each risk source, identify the probability level and consequences of possible failures.

Step 2: Conduct Scenario Analysis — Analyze potential Y2K operating scenarios. It is not possible to identify and analyze all possible Y2K operating scenarios. Therefore, the recommended approach is to identify representative More Probable Scenarios and representative Credible Worst-Case Scenarios. The More Probable Scenarios are derived from the more likely Y2K risk sources identified in Step 1. These More Probable Scenarios should be analyzed and prioritized based on probability and consequences. The analysis should identify the period(s) of vulnerability for each scenario. The Credible Worst-Case Scenarios may be single cause or combined cause scenarios that represent the worst conditions that could reasonably be expected to occur. This scenario selection requires judgment as to the readiness and operability of facilities and backup systems through critical Y2K transition periods. NERC has provided examples of both More Probable Scenarios and Credible Worst-Case Scenarios below. Coordination with Y2K Program Managers and technical personnel is important to understand actual risks. A combination of tabletop analysis and computerized studies or simulations may be used for scenario analysis.

Step 3: Develop Risk Management Strategies — Develop strategies to mitigate the consequences of each of the More Probable Scenarios and Credible Worst-Case Scenarios identified in Step 2 above. Risk management strategies can make use of staff resources, additional equipment and facilities (backup systems), special operating procedures (i.e. manual operation or use of backup communications), training, and drills. An outline of suggested risk management strategies has been provided by NERC as a starting point for consideration in regional and operating entity contingency planning.

Step 4: General Preparations — This step includes efforts to prepare for and implement the risk mitigation strategies identified in Step 3. Preparations include development of special procedures; conduct of training and drills; procurement, installation and testing of backup capabilities; review and adaptation of restoration plans for Y2K conditions; and otherwise getting systems operationally ready for Y2K transition periods.

Step 5: Power System Operation Planning — System studies should be performed based on the scenarios identified in Step 2 to determine appropriate reserve requirements, commitment of generation and transmission facilities, special system operating limitations, and operating strategies. The outcome of this step is a Y2K System Operating Plan.

Step 6: Implementation of Y2K System Operating Plan — The Y2K System Operating Plan is implemented in the final days and weeks leading up to critical Y2K transition periods and continuing through the critical periods. This step consists of the commitment, scheduling, and management of resources according to the operations plan. This step also includes monitoring system conditions and responding to conditions according to contingency response plans. This step would include system restoration and recovery operations, if necessary.

5. General Operating Principles - In implementing the above process, the following principles were utilized:

1. FRCC member systems will maintain a higher level of operating and spinning reserves during Priority 1 dates.

2. Transmission systems should be well maintained in advance of the Y2K critical periods and routine maintenance outages not allowed during the Y2K critical periods.

3. Alternative communications plans within control areas, among control areas and with the regional security coordinator need to be developed.

4. Operations personnel need to be trained on backup operation systems and plans. Training should also include restoration and black start plans and system resynchronization. Personnel need to be trained to operate with the loss of critical data and systems. Personnel expected to be on duty at the time of the Y2K critical periods should participate in any drills.

5. Availability of key operating and support personnel needs to be assured for the critical Y2K periods and should include an evaluation of holidays and vacation schedules. This will include operating entities as well as the FRCC staff.

6. Fuel supplies and inventories should be evaluated.

7. All companies are aware of and have prepared for all critical dates identified in this document.

8. The FRCC Security Coordinator has the responsibility and authority to monitor system conditions and take any necessary action to maintain the reliability of the bulk transmission system.

6. Work Plan - Using the process and principles described above, fourteen risks were identified and corresponding mitigation strategies developed. These plans have been prepared to cover a wide range of possible events, including both events which are probable and as well as events which are improbable but which carry severe consequences should they occur. These fourteen plans are set forth in Appendix A.

A schedule was then assembled comprising the following elements:

- Implementation Plans for each of fourteen mitigation strategies shown in Appendix A.
- Overview of FRCC's phased approach to addressing the Y2K issues shown in Appendix B.
- FRCC remediation and testing - FRCC expects to by Y2K ready on 6/30/99. A current summary is attached as Appendix C.
- ORS Meetings - The various strategies outlined in Appendix A have been prepared well in advance of the potential events. As such, they necessarily cover a wide range of conditions and possibilities. As each of those dates nears, however, a more accurate assessment of the conditions expected on that date may be made - conditions such as weather, generation and other equipment status, and other conditions. As such, ORS will meet just prior to certain critical dates in order to evaluate the expected conditions, and assess and modify the plans accordingly, if necessary. These meetings are reflected in the schedule below.
- NERC Y2K Drills are planned for April 9 and September 9, 1999. A more complete description is shown in the schedule below.
- Critical Dates - described in Section 2 above.

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Schedule

The following milestones are applicable to this plan.

December 3, 1998
- ORS completes first draft of plan ✓

December 10, 1998
- OC approves first draft of plan ✓

December 31, 1998
- First draft of FRCC and company Y2K contingency plans finalized. ✓
- Member companies provide snapshots of systems as requested by Security Coordinator. ✓

December 31, 1998 to January 1, 1999
- Priority 3 Critical Date (Special value: Year = 99)

January 25-26, 1999 - FRCC presentation of FRCC Contingency Plan to NERC SCS Y2K Contingency Planning Task Force. ✓

January 31, 1999 - FRCC Y2K Assessment 100% complete.

February 28, 1999
- Presentation to ORS on FPC/FPL FALS [9] ✓
- Prepare list of critical transmission equipment [7] ✓
- Prepare list of critical communications equipment [5] ✓
- Finalize update of FRCC SAP contingency and violations checklist

March 15, 1999 – ORS prepares draft of plan for April 9th drill ✓

March 31, 1999
- Individual companies complete planning, testing and training for manual monitoring of operations and EMS systems.[4] ✓
- Have plan available for backup communications to balance state generation and load across the Florida-Georgia tie [4]

April 7, 1999
- ORS meets to finalize plans for April 9th drill. ✓

April 9, 1999
- First industry-coordinated Y2K readiness drill. This drill will focus on personnel and communications. The drill will assume partial loss of

voice and data communications and partial loss of EMS/SCADA functionality. Operating entities and Security Coordinators will be required to identify key operating facilities and information requirements. Properly trained personnel will be sent to key locations and will be required to identify and communicate critical operating information over backup communications systems. The goal is to demonstrate the ability to operate electric systems with limited voice and data communications and EMS/SCADA functionality. This date is a Priority 3 Critical Date (Special value: 99* day of 1999). ✓

April 15, 1999

- All companies respond to FRCC with lessons learned from the April 9th drill. ✓

April 26, 1999

- FRCC respond to NERC with lessons learned from the April 9th drill. ✓

April 30, 1999

- Individual utilities review procedures for load shedding [1-3]
- Inventory primary and backup EMS/SCADA systems [4]
- Review list of critical facilities and identify deployment points for emergency personnel [4,5,7]

May 31, 1999

- Review adequacy of underfrequency and undervoltage schemes [1-3,8,10]
- Test voltage control systems [12]
- Examine equipment maintenance schedules of critical equipment [7]
- Verify relay date independence [9]
- Verify FALS programs date independence [9]
- Determine equipment procurement needs [5]
- Review Fuel Emergency Shortage Element and update as needed [14]
- FRCC Transmission and Stability Working Groups will evaluate scenarios 1-3 for transmission line loading problems and stability concerns [1-3,12] ✓

June 30, 1999

- Second draft of FRCC contingency plan finalized ✓
- FRCC remediation and testing 100% complete. Individual companies to provide detailed plans for outstanding items beyond this date. ✓
- ORS will review individual company contingency plans to ensure compliance with FRCC Y2K contingency plan regarding security of the bulk electric grid. ✓

July 31, 1999

- Individual companies obtain and deploy communications equipment [5] ✓
- ORS prepares draft of plan for September 9th drill ✓
- ORS will have reviewed UF restoration and blackout restoration procedures. ✓

August 22, 1999

- Priority 3 Critical Date (GPS satellite clocks expire). ✓

September 7, 1999

- ORS meets to finalize plans for September 9th drill. ✓

September 8-9, 1999

- Second industry-coordinated Y2K readiness drill. This second drill is expected to be a dress rehearsal for the rollover from December 31, 1999 to January 1, 2000. This drill may include reducing planned outages, modified commitment of resources, redispatch of generation and transmission loading, cooperation with electric market participants, and staffing of all critical facilities. The goal would be to simulate system conditions and operating plans for the Y2K transition as closely as possible without increasing risks to personnel and equipment safety or system operating security. This date is a Priority 2 Critical Date (Special value: Date = 090999). ✓

September 30, 1999

- Complete whole unit on-line tests [1-3, 8,11] ✓
- Initial resource commitment and operating plan [8, 12] ✓
- Confirm that any necessary critical facilities maintenance will be completed prior to December 1, 1999 [7] ✓
- Identify MW's at risk by fuel type for use in commitment plans [14]

October 31, 1999

- Finish installation of poke points on SCADA systems to shed load [10] ✓
- For possibility of separation, review and train with operators on the FRCC Underfrequency restoration and Blackout restoration procedures [1-3, 8] ✓
- Verify DSM programs are Y2K compliant [13] ✓

November 30, 1999

- Review preliminary load forecasts and resource commitment plan [1-3,8] ✓
- Notify markets and neighboring systems of need for assistance if necessary [1-3, 8] ✓
- Notify local authorities of expected worst case conditions [1-3, 8] ✓

- Correct backup communications anomalies discovered during April and September drills [5] ✓
- ORS to work with the FCG Environmental committee to prepare notification and request of environmental variances (needed for quick response) [11,14].
- Identify critical distribution facilities and select qualified personnel to man them [13]

December 15, 1999

- Complete final testing of quick-start units [1-3, 8, 12]

December 27, 1999

- ORS members submit updated data to Ken Hubona on Resource Plan worksheet by 1700 (72 hours covering midnight 12/31 to midnight 1/2)
- Fla/So imports are planned to be limited to 830/200 MW. Anticipated interchange within Florida will be reviewed in the FRCC Resource Plan. It is expected that from 12/31 2200 EST – 1/1 0200 EST, interchange within Florida will include normal firm and non-firm schedules but minimize changing of schedules through this period.

December 28, 1999

- ORS meets (conference call at 1300) to evaluate forecast weather and other system conditions, and to fine tune and finalize plans for December 31st. ORS will review and make recommendations for which CT's in the region will need to have on line or at synchronous speed by 10:00 pm December 31st.

December 30, 1999

- ORS members submit updated data to Ken Hubona on Resource Plan worksheet by 1200 (24 hours covering noon 12/31 to noon 1/1)
- Fla/So imports are planned to be limited to 830/200 MW. Anticipated interchange within Florida will be reviewed in the FRCC Resource Plan. It is expected that from 12/31 2200 EST – 1/1 0200 EST, interchange within Florida will include normal firm and non-firm schedules but minimize changing of schedules through this period.

December 31, 1999

- ORS meets (conference call at 0900) to finalize operational plans for transition hours
- Position operating personnel at all critical facilities (including state ties) by 6 P.M. [4]
- Review, revise and implement resource commitment plan as conditions dictate [1-3, 8, 12]

December 31, 1999 to January 1, 2000

- Priority 1 Critical Date (Rollover to 2000: Date = 010100)
- Fla/So imports are planned to be limited to 830/200 MW. Anticipated interchange within Florida will be reviewed in the FRCC Resource Plan. It is expected that from 12/31 2200 EST – 1/1 0200 EST, interchange within Florida will include normal firm and non-firm schedules but minimize changing of schedules through this period.

January 1, 2000

- FRCC conference call at 0010 via FRCC Hot Line (or Satellite Talk Group, if Hot Line is not working.)
- FRCC conference call at 0200 via FRCC Hot Line (or Satellite Talk Group, if Hot Line is not working.)

January 26, 2000

- ORS meets to discuss potential impacts for leap year critical dates.

February 28, 2000 to March 1, 2000

- Priority 2 Critical Date (Rollover in/out of leap year date)

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Appendix A

Contingency Plans for Identified Risks

Plan No. 001	Loss of Generation - Credible Worst Case
Plan No. 002	Loss of Generation - Moderate Load
Plan No. 003	Loss of Generation - Very High Load
Plan No. 004	Loss of EMS/SCADA
Plan No. 005	Loss of Communications
Plan No. 006	Loss of Load
Plan No. 007	Loss of Transmission Facilities
Plan No. 008	Interconnection Islanding
Plan No. 009	Protection Fails to Operate
Plan No. 010	Load Shedding
Plan No. 011	Environmental Monitoring and Control Lost
Plan No. 012	Voltage Control Misoperation or Failure
Plan No. 013	Loss of Distribution Systems
Plan No. 014	Loss of Fuel Supplies

an No: 001 System: FRCC
Name: Loss of Generation over January 1, 2000 AM Peak (0800)
Type: Credible Worst Case - Single Initiating Cause
Probability: Low

Risk Identification:

- Assume on January 1, between midnight and 2 AM, 25% of FRCC on-line generation capacity trips off or becomes unavailable due to Y2K problems and remains unavailable for the 8AM peak. (generation lost is identified by zones)
- Assume all nuclear units operating and loaded at 100% capacity.
- Assume Southern-to-Florida imports are constrained to 870 MWs.
- Assume extended cold weather period 12/29/1999 to 1/1/2000.

Scenario Description and Analysis:

- System peak loads are forecast to be 38,900 MWs (100% of FRCC winter peak forecast) on January 1, 2000 at 8 AM.
- Available capacity under assumptions listed above, is expected to be 42,600 MWs including 2450 MWs imports.
- Assume economic operation with all steam units and all nuclear units on line; nuclear at 100%; quick start units on line or available as needed Assume 0 MWs of additional imports available.
- No transmission problems are expected.
- Assume neighboring region has problems and imports are curtailed to 870 MWs.
- Available capacity on-line after the loss is 30,100 MWs; load forecast is 38,900 MWs.

Expected Symptoms and Effects:

- Load obligations and system limits met during early morning hours until January 1 morning load pick up.
- High imports would be expected and load conditions would be continuously monitored.

Mitigation Strategies:

- Have all steam units that can run safely within security limits on line before 10 PM Decemb 31, 1999.
- Arrange alternative external resources if available; coordinate with market regarding need additional capacity on January 1, 1999.
- Conduct tests of quick start units to minimize risk of failure to start.
- Train system operators and plant operators for these conditions and possibility of a mismatch of load and generation condition.
- Appeal to customers to reduce non-essential loads on January 1, 1999.
- Review load shedding priorities, fast acting load shed systems (FALS) and procedures; cold weather considerations.
- Notify authorities of conditions and coordinate response plan.

Implementation Plan and Schedule:

- Complete unit on-line tests by September 30, 1999.
- FRCC Transmission Task Force and Stability Working Group will evaluate this scenario for transmission line loading problems and stability concerns by May 31,1999.

Individual utilities review procedures for load shedding by April 30, 1999.

Plan No: 001 (continued)

- Review preliminary load forecasts and resource commitment plan by November 30, 1999.
- If necessary, notify markets and neighboring systems of need for assistance by November 30, 1999.
- Notify local authorities of expected worst case conditions by November 30, 1999.
- Complete final testing of quick-start units by December 15, 1999.
- Review load forecasts and resource commitment plan by December 28, 1999.
- Review, revise and implement resource commitment plan as conditions dictate by noon December 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Implement voltage reduction plan as needed January 1, 2000.
- FRCC Security Coordinator will direct load shedding in the event load obligations cannot be met.
- Be prepared to implement black start procedures.
- Notify officials of system conditions.

Verification (Approval)

Plan No: 002 **System:** FRCC
Name: Loss of Generation on January 1, 2000 @12:01 AM - normal moderate load conditions
Type: Probable Scenario
Probability: High
Risk Identification:

- Assume on January 1 at 12:01 AM, 25% of FRCC on-line generation trips off line due to Y2K problems.(generation lost is identified by zones)
- Assume all nuclear units operate at 100%capacity.
- Assume Southern-to-Florida imports are unconstrained at 3600 MWs.
- Scheduled Southern-to-Florida imports are at 2,000 MWs.

Scenario Description and Analysis:

- System midnight loads are forecast to be 40% of the FRCC forecasted Winter peak (15,600 MWs)
- Available capacity under assumptions listed above is expected to be 18,000 MWs including 2,450 MWs imports.
- Assume economic operation with steam units and all nuclear units; nuclear at 100%; quick start units available as needed
- No transmission problems are expected.
- Extenuating circumstances:
  - Assume neighboring region has problems and imports are curtailed to the externally located Scherer unit at 870 MWs.
  - Available Capacity on line after the 25% loss is 13,450 MWs. Load is 15,600 MWs.

Expected Symptoms and Effects:

- Excessive pull on the Florida / Southern interface in excess of 4,700 MWs (3,900 (+), expected to trip), separation would occur, confirming 0 import (additional loss of 2,450 MWs).
- Underfrequency conditions would occur which may be arrested by the Florida underfreque program.
- Islanding will occur in the Florida region. Blackout may occur in the Florida region.

Mitigation Strategies:

- Have all steam units that can run safely within security limits on line before 10 p.m., December 31, 1999.
- Quick start generation required to be on line or up to synchronous speed prior to midnight be determined by ORS during the December 27 conference call and revised as appropriat up to the transition time.
- Reduce Imports to 830/200 MWs prior to midnight to allow loss of 3,900 MWs without separation of the interface.
- Conduct tests of quick start units to minimize risk of failure to start.
- Train system operators and plant operators for these conditions and possibility of a mismatch of load and generation condition.
- Appeal to customers to reduce non-essential loads.

'n No: 002 (continued)

- Review load shedding priorities, fast acting load shed systems (FALS) and procedures.

- Notify authorities of conditions and coordinate response plan.

Implementation Plan and Schedule:

- FRCC Transmission Task Force and Stability Working Group will evaluate for line load problems and stability by May 31, 1999.
- Review adequacy of Underfrequency load program by May 31, 1999.
- ORS will review UF restoration and Blackout restoration procedures by July 31, 1999.
- Complete unit on-line tests by September 30, 1999.
- For possibility of separation, review and train operators on FRCC Underfrequency restoration and Blackout restoration procedures by October 31, 1999
- Review preliminary load forecasts and resource commitment plan by November 30, 1999.
- If necessary, notify markets and neighboring systems of need for assistance by November 30, 1999.
- Notify local authorities of expected worst case conditions by November 30, 1999.
- Complete final testing of quick-start units by December 15, 1999.
- Review load forecasts and resource commitment plan by December 28, 1999.
- Review, revise and implement resource commitment plan as conditions dictate by noon December 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

Rely on Underfrequency separation procedure as needed.

Verification (Approval)

Plan No: 003 **System:** FRCC

Name: Loss of Generation on January 1, 2000 @12:01 AM – very high load conditions

Type: Probable Scenario

Probability: Low

Risk Identification:

- Assume on January 1, 2000 at 12:01 AM, 25% of FRCC on-line generation trips off line due to Y2K problems (generation lost is identified by zone). Assume all nuclear units operate at 100% capacity.
- Assume Southern-to-Florida imports are constrained to 870 MWs.
- Assume extended cold weather period December 29, 1999 to January 1, 2000.

Scenario Description and Analysis:

- System midnight loads are forecast to be 70% of FRCC Winter peak forecast on January 1, 2000 at 8 AM (27,000 MWs)
- Available capacity under worst case assumptions listed above is expected to be 29,500 MWs plus 0 MWs additional imports.
- Assume operation with steam units and all nuclear units on line; nuclear at 100%; quick start units available as needed.
- No transmission problems are expected.
- Extenuating circumstances:
  - Assume neighboring region has problems and imports are curtailed to the externally located Scherer unit at 870 MWs.
  - Available Capacity on line after the 25% loss is 22,000 MWs. Load is 27,000 MWs.

Expected Symptoms and Effects:

- Excessive pull on the Florida / Southern interface in excess of 4,700 MWs (6,750 (+), expected to trip), separation would occur, confirming 0 import (additional loss of 870 MWs).
- Extreme underfrequency conditions would occur which will not be arrested by the Florida underfrequency program.
- Blackout or multiple islanding will occur in the Florida region.

Mitigation Strategies:

- Have all steam units that can run safely within security limits on line before 10 p.m., December 31, 1999.
- Quick start generation required to be on line or up to synchronous speed prior to midnight will be determined by ORS during the December 28 conference call and revised as appropriate up to the transition time.
- Increase Exports to greater than 2,100 MWs prior to midnight to allow loss of 6,750 MWs without separation of the interface.
- Conduct tests of quick start units to minimize risk of failure to start.
- Train system operators and plant operators for these conditions and probability of a misma of load and generation condition.
- Appeal to customers to reduce non-essential loads.
- 'eview load shedding priorities, fast acting load shed systems (FALS) and procedures.

Plan No: 003 (continued)

- Notify authorities of conditions and coordinate response plan.

Implementation Plan and Schedule:

- Review adequacy of Underfrequency load program by May 31, 1999.
- FRCC Transmission Task Force and Stability Working Group will evaluate for line load problems and stability by May 31, 1999
- ORS will review UF restoration and Blackout restoration procedures by July 31, 1999.
- For possibility of separation, review and train operators on FRCC Underfrequency restoration and Blackout restoration procedures by October 31, 1999Complete unit on-line tests by September 30, 1999.
- Review preliminary load forecasts and resource commitment plan by November 30, 1999.
- If necessary, notify markets and neighboring systems of need for assistance by November 30, 1999.
- Notify local authorities of expected worst case conditions by November 30, 1999.
- Complete final testing of quick-start units by December 15, 1999.
- Review load forecasts and resource commitment plan by December 28, 1999.
- Review, revise and implement resource commitment plan as conditions dictate by noon December 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

Rely on black start procedure.

Verification (Approval)

Plan No: 004 **System:** FRCC
Name: EMS/SCADA – loss of system monitoring and control functions
Type: Moderately Probable Scenario
Probability: Potentially high impact

Risk Identification:

- Loss of some EMS/SCADA functions- moderate probability / high impact
- Loss of RTUs - moderate probability
- Communicating bad data – low probability / high impact.
- EMS overload during burst of high activity - low probability / high impact.

Scenario Description and Analysis:

- Assume normal moderate load conditions.
- Immediately following midnight and for two hours thereafter, a large FRCC utility loses all system monitoring and control functions and/or receives inaccurate or unreliable data.

Expected Symptoms and Effects:

- Large utility is unable to remotely control or monitor critical functions of its system through its primary EMS system.
- Unable to monitor any other FRCC system.
- Unable to monitor state ties.
- Situation is further confused by receipt of bad data.
- Loss of IUL data.
- Loss of security coordinator function by FPL.
- Contingency analysis programs become unreliable due to no data or unreliable data.

Mitigation Strategies:

- Each member system inventory its back-up systems to determine whether each system is sufficiently similar to the primary system so as to be susceptible to the same Y2k problems, or whether it is sufficiently different so as not to be vulnerable to the same flaws.
- Identify critical facilities and prepare list.
- Identify manual monitoring and operating procedures, train personnel, conduct drills
- Each member utility conducts tests of its EMS back-up systems.
- Each member utility devises or reviews existing plan for operating system in event of EMS outage (i.e. hold units at present level, etc.)
- Prepare plan for backup communications to balance state generation and load across the Florida tie.
- Position operating personnel on site at all critical transmission and generation facilities
- Arrange for radio communications to be available as backup to primary voice communications to manual monitoring and control
- Critical information technology staff available to recover EMS/SCADA
- Plan for neighboring systems to assist as able.
- If FPL loses EMS, FPC assumes security coordinator function.

Plan No: 004 (Continued)

Implementation Plan and Schedule:

- Prepare list of critical equipment by February 28, 1999.
- Individual companies complete planning, testing and training for manual monitoring of operations and EMS systems by March 31, 1999.
- Have plan available for backup communications to balance state generation and load across the Florida-Georgia tie by March 31, 1999.
- Review list of critical facilities and identify deployment points for emergency personnel by April 30, 1999.
- Inventory primary and backup EMS/SCADA systems by May 31, 1999.
- Position operating personnel on site at all critical transmission and generation facilities (including state ties) by 6 P.M., December 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Be prepared for FPC to maintain SC function as long as necessary in event FPL EMS remains down for an extended period.
- Notify officials of system conditions as needed.

Verification (Approval)

- Participate in NERC April 9, 1999 communications drill.
- Review list of critical facilities and identify deployment points for emergency personnel by April 30, 1999.
- Determine equipment procurement needs by May 31, 1999.
- Obtain and deploy equipment by July 31, 1999.
- Correct backup communications anomalies discovered during April and September drills by November 30, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Make public energy conservation appeals.
- Implement DSM programs.
- Implement firm load reductions.

Verification:(Approval)

Plan No: 006 **System:** FRCC
Name: Load – Loss of load and/or uncharacteristic load pattern
Type: Probable Scenario
Probability: High – potentially high impact
Risk Identification:

- Assume risk of loss of 25% of Industrial/Commercial load on January 1, 2000 @ midnight (925mw).
- Assume risk of loss at 5% of rural/residential load on January 1, 2000 @ midnight (740 mw).
- Assume risk of continued loss of 25% of Industrial/Commercial load on January 1, 2000 @ 7 AM (2,220 mw).
- Assume all rural/residential loads restored by 7 AM.

Scenario Description and Analysis:

- Assume 50% load (18,500 mw) on January 1, 2000 @ midnight.
- Assume 40% load (14,800 mw) on January 1, 2000 @ 4 AM.
- Assume 80% load (29,600 mw) on January 1, 2000 @ 7 AM.
- Assume 45-50% of total load on a weekday is Industrial/Commercial load.
- Assume 20% of total load (3,700 mw) on January 1, 1000 @ midnight is Industrial/Commercial load.
- Assume 20% of total load (2,960 mw) on January 1, 1000 @ 4 AM is Industrial/Commercial load.
- Assume 30% of total load (8,880 mw) on January 1, 1000 @ 7 AM is Industrial/Commercial load.

Expected Symptoms and Effects:

- Highest impact should be on January 1, 2000 @ midnight due to possible large instantaneous loss of load.
- Due to extra generation on line and at minimum load as a mitigation strategy for the loss of generation, unit response for load reduction may be reduced.
- Load loss should not be large enough to create high voltage problems.

Mitigation Strategies:

- Communicate with large Industrial/Commercial customers to determine probability of load loss.
- Maintain level of unit output so some units may respond to instantaneous load loss.
- Insure Reactors are ready in case of voltage problems.

Implementation Plan and Schedule:

- No testing planned for load loss.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Restore lost load as soon as possible.
- Reduce generation to match load.
- Close Reactors.

Verification (Approval)

Plan No: 007 **System:** FRCC
Name: Transmission - loss of transmission facilities
Type: Credible Worst Case Scenario - Single Initiating Cause
Probability: Low
Risk Identification:
- Low probability of loss of bulk transformers
- Low probability of loss of large capacitors/reactors
- Low probability of loss of breakers

Scenario Description and Analysis:
- Due to loss of equipment, added stress on nearby equipment causes failure

Expected Symptoms and Effects:
- Possible cascading of failing equipment, leading to load shed (manual or automatic)

Mitigation Strategies:
- Correct any known critical equipment problems through maintenance or replacement.

Implementation Plan and Schedule:
- Identify critical transmission equipment by February 28, 1999.
- Review list of critical facilities and identify deployment points for emergency personnel by April 30, 1999.
- Examine equipment maintenance schedules of critical equipment by May 31, 1999.
- Confirm by September 30, 1999 that any necessary critical facilities maintenance will be completed prior to December 1, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):
- Load shed (manual or automatic)

Verification (Approval)

Plan No: 008 **System:** FRCC
Name: Transmission - interconnection islanding under normal conditions
Type: Credible Worst Case Scenario - Single Initiating Cause
Probability: Low
Risk Identification:

- Assume risk of loss of interconnection between Florida and Southern.
- Assume Southern-to-Florida imports are unconstrained to 3600 MWs.
- Scheduled Southern-to-Florida imports are at 2,000 MWs.
- No additional loss of generation resources occurs.

Scenario Description and Analysis:

- System midnight loads are forecast to be 40% of the FRCC forecasted Winter peak (15,600 MWs)
- Available capacity under assumptions listed above is expected to be 18,000 MWs including 2,450 MWs imports.
- Assume economic operation with steam units and all nuclear units; nuclear at 100%; quick start units available as needed
- No transmission problems are expected.
- Extenuating circumstances:
  - Assume the two 500kv lines (Duval - Hatch and Duval – Thalman) trip for a Y2K problem. The expected response would be for the Duval – Kingsland 230kv & Columbia – Suwannee 115kv to trip and the Ft. White bus to separate.
  - Assume FRCC resource loss of 2,000 MWs.
  - Available capacity after separation is 15,550 MWs plus quick start generation (2,500 MWs), load is ~ 15,300 MWs and real time generation is 13,600 MWs.

Expected Symptoms and Effects:

- With a generation / load mismatch of ~1,700 MWs, underfrequency load shed would occur.
- Reserves on line are sufficient to raise generation (and thus frequency) if necessary. Underfrequency load shed may be sufficient to shed enough load to return the Generation / load match to 60 Hz. and automatically allow Ft. White to synch.
- Load could be restored with on line generation (operating reserves) and / or quick start gas turbines.

Mitigation Strategies;

- Ride through the separation with expectations of a fast recovery.
- Reduce imports to 830/200 MWs to prevent separation when the 2 - 500 kV lines trip.
- Place as much non-quick start generation on line before 10 p.m., December 31, 1999.
- Run all quick start generation up to synchronous speed prior to midnight.
- Train system operators and plant operators for these conditions and possibility of a misn of load and generation condition.

Implementation Plan and Schedule:

- Review adequacy of Underfrequency load program by May 31, 1999.
  Review Blackout restoration procedures by July 31, 1999.

Complete unit on-line tests by September 30, 1999.

- Initial resource commitment and operating plan by September 30, 1999.
- Review and train operators on Underfrequency restoration procedures by October 31, 1999
- Review preliminary load forecasts and resource commitment plan by November 30, 1999.
- If necessary, notify markets and neighboring systems of need for assistance by November 30, 1999.
- Notify local authorities of expected worst case conditions by November 30, 1999.
- Complete final testing of quick-start units by December 15, 1999.
- Review load forecasts and resource commitment plan by December 28, 1999.
- Review, revise and implement resource commitment plan as conditions dictate by December 31, 1999..

Emergency Response Alternatives (Mitigation Strategies Fail):

Verification (Approval)

Plan No: 009 **System:** FRCC

Name: Protection - fails to operate leads to equipment damage or cascading outage or both

Type: Credible Worst Case Scenario - Single Initiating Cause

Probability: Low

Risk Identification:

- Low probability of non-electromechanical relays misoperate
- Low probability of computer controlled load shed programs that use relays misoperate

Scenario Description and Analysis:

- Fault causes false tripping or misoperation
- Fast Acting Load Shed (FALS) programs misoperate, incorrectly shedding load, or failing to shed when appropriate

Expected Symptoms and Effects:

- Improper relay operation fails to protect equipment, or operates unnecessarily to create outage.
- FALS programs fail to shed load resulting in overloaded equipment, voltage collapse, loss of load.
- FALS programs are activated when not needed, load is shed unnecessarily.

Mitigation Strategies:

- Confirm that relays are not date dependent.
- Confirm that FALS programs are not date dependent.

Implementation Plan and Schedule:

- Presentation to ORS on FPC/FPL FALS by February 28, 1999.
- Verify relay date independence by May 31, 1999.
- Verify FALS programs date independence by May 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Could require manual load shed to maintain stability.
- De-activate FALS programs

Verification (Approval)

Plan No: 010 **System:** FRCC

Name: Load Shedding – underfrequency or undervoltage load shedding or both misoperate or fail to operate

Type: Credible Worst Case Scenario - Single Initiating Cause

Probability: Low

Risk Identification:

- Assume 1,100 MW loss of generation in FRCC Region due to Y2K problems
- Assume FL separates from Eastern Interconnection at the planned locations.
- Assume Load Shedding underfrequency and undervoltage schemes do not function

Scenario Description and Analysis:

- Load is expected to be 27,000MW at Midnight December 31, 1999
- Import is 1800 MW at time of separation from Eastern Interconnection.
- Need to shed 2,900 MW of load for 60 Hz operation.

Expected Symptoms and Effects:

- Manual load shedding may be too slow to stop cascading with islands developing
- Possible damage to generators due to operation at low frequency.

Mitigation Strategies:

- Install poke points on SCADA systems to quickly shed load.
- Review underfrequency and undervoltage schemes to assure minimal problems.
- Review possible actions with System Operators

..plementation Plan and Schedule:

- Review underfrequency and undervoltage schemes by May 31, 1999.
- Installation of poke points on SCADA systems to shed load completed by October 31, 1999.
- Review and train operators on the FRCC UF restoration and Blackout restoration procedures by October 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Manually shed load if systems fail.

Verification (Approval)

Plan No: 011 **System:** FRCC
Name: Environmental Monitoring & Control lost
Type: Credible Worst Case Scenario - Multiple Initiating Cause
Probability: Low

Risk Identification:
- Assume risk of loss of 1200 MW of capacity due to Environmental Monitoring.
- Assume risk of loss of 1200 MW of capacity due to Control Failure.
- Assume import at 1800 MW at midnight on December 31, 1999.
- Separation of FL does not occur but frequency is low at 59.93 Hz.

Scenario Description and Analysis:
- Load is expected to be 27,000 MW at Midnight December 31, 1999
- Import is 1800 MW at Midnight December 31, 1999 and ties do not trip.
- 1200 MW of capacity trips due to Control Failure.
- Environmental Monitoring fails on 1200 MW of capacity.

Expected Symptoms and Effects:
- Loss of Environmental Monitoring requires 1200 MW of capability taken off line
- Loss of additional 1200 MW of capability will result in loss of firm load.

Mitigation Strategies:
- Perform on-line tests to minimize probability of loss of units.
- Have generating stations secure exemption from Environmental Monitoring requirements from December 30, 1999 to January 15, 2000.
- Review load shedding priorities and procedures.

Implementation Plan and Schedule:
- Complete unit on-line testing by September 30, 1999.
- ORS to work with the FCG Environmental Committee to prepare notification and request of environmental variances (including a possible draft of a Governor emergency order) by November 30, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):
- Be prepared to implement load shedding in event load obligation cannot be met.
- Environmental personnel will keep EPA informed of testing and any failures of Environmental Monitoring.
- Environmental personnel will have plan to extend exemption for Environmental Monitoring as needed.

Verification (Approval)

Plan No: 012 System: FRCC
Name: Voltage Control - device misoperation or failure
Type: Credible Worst Case Scenario - Single Initiating Cause
Probability: Low

Risk Identification:

- Assume risk of device malfunction or failure of 20% of voltage control devices clustered to the critical interface based on TTF studies.

Scenario Description and Analysis:

- Assume winter peak conditions.
- Assume import level of 2800 MW.
- Assume normal commitment of generating resources to meet peak load.
- Extenuating circumstances:
  - 20% of voltage control devices fail to operate as the FRCC reaches peak conditions.
  - 20% of voltage control devices fail to operate upon worst contingency based on TTF studies.

Expected Symptoms and Effects:

- Base case expected to have low voltage based on incorrect reactor/capacitor switching and generator excitation systems.
- Further problems based on first contingency operation.

Mitigation Strategies:

- Perform tests on switching systems.
- Perform tests on generator excitation systems.
- Perform tests on quick-start peakers.
- Commitment of additional generating resources.
- Train operators.

Implementation Plan and Schedule:

- Complete TTF study by May 31, 1999.
- Test voltage control systems by May 31, 1999.
- Develop initial resource commitment and operating plan by September 30, 1999.
- Complete final testing of quick-start units by December 15, 1999.
- Review, revise and implement resource commitment plan as conditions dictate by December 31, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Implement voltage reduction.
- Prepare for load shed.
- Notify appropriate authorities.

Verification (Approval)

Plan No: 013 **System:** FRCC
Name: Distribution - loss of distribution systems
Type: Credible Worst Case Scenario - Single Initiating Cause
Probability: Low
Risk Identification:
Distribution system events causing load loss:
- in local areas, not significantly affecting the transmission system. – high probability / low impact
- in a large area and affecting system generation dispatch and transmission equipment loading. – low probability / high impact
- DSM misoperation, system wide. – low probability / moderate impact
- DSM misoperation, in local areas. – moderate probability / low impact

Scenario Description and Analysis:
- Typical system loads.
- Adequate generating capacity.
- Adequate transmission capacity.
- Other Y2K contingencies may be in process.

Expected Symptoms and Effects:
- Unexpected loss of load requiring minor generation adjustments.
- Unexpected loss of significant amount of load requiring generating unit redispatch and possible transmission system reconfiguration.

[illegible]igation Strategies:
- Examine and test DSM programs for Y2K compliance
- Deploy personnel to key substations to perform manual load restoration if needed.

Implementation Plan and Schedule:
- Verify DSM programs are Y2K compliant by October 31, 1999.
- Identify critical distribution facilities and select qualified personnel to man them by November 30, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):
- Make public energy conservation appeals.
- Implement DSM programs.
- Notify public officials as needed.

Verification (Approval)

Plan No: 014 System: FRCC
Name: Loss of External Fuel Supplies, Natural Gas Pipeline on January 1, 2000 at 12:01 AM
Type: Credible Worst Case Scenario - Multiple Initiating Cause
Probability: Low to Moderate
Risk Identification:

- Loss of natural gas supply to peninsula Florida due to pipeline Y2K problems.

Scenario Description and Analysis:

- Assume normal to moderate load conditions, 27,000 MW at 8:00 AM
- Available capacity on-line to meet above expected load is expected to be 31,100 MWs, including 2450 MWs of imports.
- Assume operation with steam units and all nuclear units on line, nuclear at 100%; quick start units available as needed.
- No transmission problems are expected.

Expected Symptoms and Effects:

- Loss of 3,500 MWs of NG generation due to either no backup fuel or inoperable backup fuel systems.

Mitigation Strategies:

- Have NG generating units procure adequate backup fuel supply (3-5 day supply).
- Arrange alternative external resources if available; coordinate with market regarding need for additional capacity on January 1.
- Train system operators and plant operators for efficient fuel swapping capability.

Implementation Plan and Schedule:

- Review Fuel Emergency Shortage Element and update as needed by May 31, 1999.
- Identify MW's at risk by fuel type for use in commitment plans by September 30, 1999.
- ORS to work with the FCG Environmental Committee to prepare notification and request of environment variances by November 30, 1999.

Emergency Response Alternatives (Mitigation Strategies Fail):

- Notify officials of system conditions as needed.
- Be prepared to implement the Capacity Emergency Shortage Element if needed.

Verification (Approval)

Appendix B

FRCC Y2K Plan

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FRCC Y2K Plan

The FRCC Plan will parallel the NERC Y2K plan and consist of three phases:

Phase 1 – Sharing of Y2K information; May – September 1998

- NERC will mobilize coordination and information sharing of Y2K problems and solutions.

FRCC Regional Coordinator and Technical Subgroup representatives selected. Y2K contacts for each FRCC member are established.

FRCC members are participating in the data gathering and coordination efforts through the work of their Y2K contacts. Regional information is shared through the activities of the Regional Coordinator and the Technical Subgroup representatives.

FRCC members were provided a NERC Y2K Electric System Readiness Assessment that will facilitate monthly reporting of the status of Y2K activities.

FRCC has planned a special meeting for early October where members will report on their Y2K Progress.

Phase 2 – Identification of potential weaknesses in system security; September 1998 – July 1999

- NERC will facilitate efforts by the Regional Reliability Councils and responsible operating entities to resolve the known Y2K technical problems.

FRCC members will participate in system simulations and engineering studies to understand expected and worst-case scenarios. The NERC System Readiness Assessment Surveys may be utilized to help determine the scenarios for study.

FRCC members will determine corrective and mitigation strategies.

FRCC members will submit periodic progress reports using an established list of criteria.

Phase 3 – Operational Preparedness; July 1999 – January 2000

- NERC will review the preparation of contingency plans and operating procedures.

FRCC members will develop plans and procedures for operation during the Y2K transition.

FRCC members will participate in training and system drills to ensure readiness.

FRCC members will develop operating plans to mitigate the consequences of adverse Y2K problems.

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Several Y2K critical dates have been identified:

08/22/99 - Satellite Date/Time Expiration.
09/09/99 - 09/09/99 Rollover.
12/31/99 and 01/01/2000 – Rollover to 2000.
02/28/2000 and 02/29/2000 – Leap Year.

Appendix C

FRCC Summary of Y2K Readiness

5

-----Original Message-----
From: jim-thompson@reliantenergy.com
[mailto:jim-thompson@reliantenergy.com]
Sent: Monday, December 27, 1999 4:57 PM
To: Howard, Donna
Cc: Mike_Antonell@reliantenergy.com; james-waite@reliantenergy.com; McNeeley_Mi@reliantenergy.com; cesar-seymour@reliantenergy.com; Broussard_Rene@reliantenergy.com
Subject: Re: FRCC Y2K Contingency Plan

Ms. Howard,

As per our recent discussion, I am requesting that FRCC consider the Reliant Energy Indian River steam units an exception to the FRCC Y2K Dec. 31st, 2000 operating criteria. As you are aware these three units, providing a cumulative 619 mws of generating capacity, have been purchased by Reliant Energy with 593 mws of that capacity sold back to Orlando Utilities Commission under a Power Purchase Agreement. Under the terms of that agreement (or PPA) Orlando may schedule energy from the units and Reliant is compensated for such energy schedules under specific formulas within the PPA. This compensation scheme is the issue that has required Reliant Energy to expect that the Indian River units will be treated differently than steam units that are owned by other FRCC control area generators. Unless Reliant Energy receives an energy schedule from OUC, OUC is not required to compensate Reliant Energy for bring those units on line. Should a viable energy market exist at the time power is produced, Reliant Energy could sell energy produced into that market to receive its compensation. Neither of these situations appear to exist at this point in time. For the FRCC Y2K time frame beginning Dec. 31st, 2000 at 10 PM eastern time, Orlando Utilities has informed me that they do not intend to schedule energy under the terms and conditions of the Indian River PPA. Additionally, it seems clear that virtually no forward or spot energy market exists in Florida for that time due to mild weather and excess generation on line This leaves Reliant Energy with no compensation for bringing these units on-line and potentially, no load to serve with the energy produced. These issues would tend to make Reliant appear more like an Independent Power Producer than an FRCC control area. Please understand that it is Reliant Energy's intent to respond appropriately in order to serve the native load requirements of FRCC and should an actual energy emergency exist, Reliant will respond immediately - compensation not withstanding. However, given the current situation, Reliant does not see a need to bring the Indian River units on line to meet the current FRCC Y2K plan and is not issuing instructions to the Indian River operating personnel to do so.

Thank you ....Jim Thompson, Reliant Energy

Phone: 713.207.5525
Pager: 80.465.2985

6

-----Original Message-----
From: jim-thompson@reliantenergy.com
[mailto:jim-thompson@reliantenergy.com]
Sent: Monday, December 27, 1999 4:57 PM
To: Howard, Donna
Cc: Mike_Antonell@reliantenergy.com; james-waite@reliantenergy.com; McNeeley_Mi@reliantenergy.com; cesar-seymour@reliantenergy.com; Broussard_Rene@reliantenergy.com
Subject: Re: FRCC Y2K Contingency Plan

Ms. Howard,

As per our recent discussion, I am requesting that FRCC consider the Reliant Energy Indian River steam units an exception to the FRCC Y2K Dec. 31st, 2000 operating criteria. As you are aware these three units, providing a cumulative 619 mws of generating capacity, have been purchased by Reliant Energy with 593 mws of that capacity sold back to Orlando Utilities Commission under a Power Purchase Agreement. Under the terms of that agreement (or PPA) Orlando may schedule energy from the units and Reliant is compensated for such energy schedules under specific formulas within the PPA. This compensation scheme is the issue that has required Reliant Energy to expect that the Indian River units will be treated differently than steam units that are owned by other FRCC control area generators. Unless Reliant Energy receives an energy schedule from OUC, OUC is not required to compensate Reliant Energy for bring those units on line. Should a viable energy market exist at the time power is produced, Reliant Energy could sell energy produced into that market to receive its compensation. Neither of these situations appear to exist at this point in time. For the FRCC Y2K time frame beginning Dec. 31st, 2000 at 10 PM eastern time, Orlando Utilities has informed me that they do not intend to schedule energy under the terms and conditions of the Indian River PPA. Additionally, it seems clear that virtually no forward or spot energy market exists in Florida for that time due to mild weather and excess generation on line This leaves Reliant Energy with no compensation for bringing these units on-line and potentially, no load to serve with the energy produced. These issues would tend to make Reliant appear more like an Independent Power Producer than an FRCC control area. Please understand that it is Reliant Energy's intent to respond appropriately in order to serve the native load requirements of FRCC and should an actual energy emergency exist, Reliant will respond immediately - compensation not withstanding. However, given the current situation, Reliant does not see a need to bring the Indian River units on line to meet the current FRCC Y2K plan and is not issuing instructions to the Indian River operating personnel to do so.

Thank you ....Jim Thompson, Reliant Energy

Phone: 713.207.5525
Pager: 80.465.2985

EXHIBIT CJC-6

Sources of Electricity in Florida

FP&L				
MWh Origins	Self Generated	Florida Purchase	Out-of-State Purch	Total MWh
1998	83.1%	10.6%	6.2%	96,271,252
1997	79.1%	13.6%	7.3%	88,599,172
1996	78.4%	14.7%	6.9%	86,758,313

FPC				
MWh Origins	Self Generated	Florida Purchase	Out-of-State Purch	Total MWh
1998	79.0%	15.7%	5.2%	39,287,572
1997	69.6%	21.8%	8.6%	35,286,739
1996	68.4%	24.9%	6.6%	35,334,439

TECO				
MWh Origins	Self Generated	Florida Purchase	Out-of-State Purch	Total MWh
1998	88.9%	9.1%	2.1%	19,331,629
1997	93.2%	6.5%	0.3%	19,034,534
1996	95.2%	4.8%	0.0%	18,979,907

The State of Florida				
MWh Origins	Self Generated	Florida Purchase	Out-of-State Purch	Total MWh
1998	82.8%	11.7%	5.5%	154,890,453
1997	78.6%	14.7%	6.7%	142,920,445
1996	78.2%	15.9%	5.9%	141,072,659

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EXHIBIT CJC-7

Purchase Power Expenses in Florida

FP&L Purchase Power				
PPwr Data	Energy Charge	Demand Chg	Total Rate	PPwr MWh
1998	16.96	30.63	47.59	16,233,737
1997	18.02	26.95	44.97	18,507,173
1996	18.56	25.08	43.64	18,750,949

FPC Purchase Power				
PPwr Data	Energy Charge	Demand Chg	Total Rate	PPwr MWh
1998	22.46	31.59	54.06	8,231,407
1997	20.92	27.22	48.14	10,730,248
1996	22.43	25.46	47.89	11,154,884

TECO Purchase Power				
PPwr Data	Energy Charge	Demand Chg	Total Rate	PPwr MWh
1998	27.69	13.33	41.02	2,150,224
1997	32.19	19.69	51.88	1,297,253
1996	25.78	27.67	53.45	915,828

Florida IOU Purchase Power				
PPwr Data	Energy Charge	Demand Chg	Total Rate	PPwr MWh
1998	19.53	29.53	49.06	26,615,368
1997	19.65	26.73	46.38	30,534,674
1996	20.17	25.29	45.47	30,821,661

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EXHIBIT CJC-8

ESTIMATED ENERGY COSTS IN FLORIDA
System Lambda for Generation, Energy Charge for Purchased Power

FP&L							
	System Lambda and Gen%		Florida Purch Cost and %		Out-of-State Purch Cost and %		**Combined Rate**
1998	20.30	83.1%	17.09	10.6%	16.72	6.2%	**19.73**
1997	23.09	79.1%	18.24	13.6%	17.62	7.3%	**22.04**
1996	23.22	78.4%	18.66	14.7%	18.34	6.9%	**22.21**

FPC							
	System Lambda and Gen%		Florida Purch Cost and %		Out-of-State Purch Cost and %		**Combined Rate**
1998	18.30	79.0%	23.34	15.7%	19.84	5.2%	**19.18**
1997	21.19	69.6%	21.68	21.8%	19.02	8.6%	**21.11**
1996	21.47	68.4%	23.30	24.9%	19.15	6.6%	**21.78**

TECO							
	System Lambda and Gen%		Florida Purch Cost and %		Out-of-State Purch Cost and %		**Combined Rate**
1998 **	13.94	88.9%	27.91	9.1%	26.70	2.1%	**15.46**
1997	15.91	93.2%	32.14	6.5%	33.20	0.3%	**17.02**
1996	14.91	95.2%	25.78	4.8%	33.05	0.0%	**15.43**

** 1998 TECO System Lambda is the '97 TECO Lambda Scaled by the FPC and FPL 97 and 98 Lambdas

Joint Dispatch of Florida IOUs							
	System Lambda and Gen%		Florida Purch Cost and %		Out-of-State Purch Cost and %		**Combined Rate**
1998 **	21.14	82.8%	20.26	11.7%	17.95	5.5%	**20.87**
1997	24.39	78.6%	20.33	14.7%	18.16	6.7%	**23.37**
1996	25.06	78.2%	20.77	15.9%	18.57	5.9%	**24.00**